DIVISION OF CONSUMER ADVOCACY
Department of Commerce and
Consumer Affairs
335 Merchant Street, Room 326
Honolulu, Hawaii 96813
Telephone: (808) 586-2800

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of the Application of)
)
HAWAIIAN ELECTRIC COMPANY, INC.) DOCKET NO. 04-0113
)
For Approval of Rate Increases and Revised)
Rate Schedules and Rules.)

DIVISION OF CONSUMER ADVOCACY'S
DIRECT TESTIMONIES, EXHIBITS AND WORKPAPERS

Pursuant to the agreed upon Schedule of Proceedings approved in Order No. 21727 the Division of Consumer Advocacy hereby submits its **DIRECT TESTIMONIES, EXHIBITS AND WORKPAPERS** in the above docketed matter.

DATED: Honolulu, Hawaii, June 28, 2005.

Respectfully submitted,

By Cheryl S. Kikuta
CHERYL S. KIKUTA
Utilities Administrator

DIVISION OF CONSUMER ADVOCACY

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CA-T-1
DOCKET NO. 04-0113

DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Overall Revenue Requirement, Test Year Concept, Sales Revenues, Miscellaneous Revenues, Combined Heat & Power, Distributed Generation, Fuel & Purchased Power Adjustments, Production Operations and Maintenance Expense, Depreciation and Amortization Expense, Net Plant in Service, Other Rate Base, Plant Held for Future Use, HECO Undergrounding Policy, Fuel Inventory, Working Cash.

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DIRECT TESTIMONY OF MICHAEL L. BROSCH

I. INTRODUCTION AND QUALIFICATIONS.

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael L. Brosch. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a principal and the President of Utilitech, Inc. The firm's business and my responsibilities are primarily related to special services work for utility regulatory clients, including rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses, and special investigations of utility operations and ratemaking issues.

Q. WILL YOU SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE IN THE FIELD OF UTILITY REGULATION?

A. I have prepared Exhibit CA-100 for this purpose.

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN REGULATORY ENGAGEMENTS BEFORE THE HAWAII PUBLIC UTILITIES COMMISSION?

A. Yes. I submitted written direct testimony on behalf of the Hawaii Department of Commerce and Consumer Affairs, Division of Consumer Advocacy ("Consumer Advocate" or "CA") in rate case proceedings involving Hawaii

Electric Light Company Docket No. 6999, Maui Electric Company Docket No. 7000, Hawaiian Electric Company Docket No. 7700, GTE Hawaiian Telephone Company Docket No. 94-0298 and The Gas Company Docket No. 00-0309.

In addition to these rate case engagements, I assisted the Consumer Advocate in its analysis and Statement of Position preparation in Docket No. 97-0035 involving the sale of The Gas Company by from Broken Hill Proprietary Company, Ltd., and in Docket No. 03-0051 involving the subsequent sale of The Gas Company by Citizens Communications Company ("Citizens") to K-1 USA Ventures, Inc. In addition, I was involved in the recent analysis and Statement of Position preparation regarding the proposed sale of the Kauai Electric Division by Citizens in Docket Nos. 00-0352 and 02-0060 and the analysis and Statement of Position preparation in the proposed sale of Verizon Hawaii to entities controlled by the Carlyle Group in Docket No. 04-0140.

Q. ON WHOSE BEHALF ARE YOU NOW APPEARING?

A. I am testifying on behalf of the Hawaii Department of Commerce and Consumer Affairs, Division of Consumer Advocacy ("Consumer Advocate" or "CA") in this proceeding.

Q. WHAT ARE THE FUNCTIONAL AREAS OF THE CONSUMER ADVOCATE'S PRESENTATION IN THIS DOCKET, FOR WHICH YOU ARE DIRECTLY RESPONSIBLE?

A. My testimony explains the test year concept employed in this Docket as well as the development of the Consumer Advocate's recommended test year sales and associated revenue levels, non-fuel production O&M expenses and depreciation and amortization expenses includable in the revenue requirement under this concept. I also sponsor the net plant in service, inventories, working cash and other balances includable in the test year rate base. My testimony also addresses combined heat and power, distributed generation, energy cost adjustment and Hawaiian Electric Company, Inc.'s ("HECO" or "Company") distribution facilities undergrounding policy matters. In a separately filed testimony designated CA-T-5, I discuss issues involving HECO's proposed cost of service allocation studies, proposed revenue distribution among rate classes, and certain rate design issues.

Q. HOW ARE THE CONSUMER ADVOCATE ACCOUNTING SCHEDULES ORGANIZED?

A. The Consumer Advocate's Accounting Schedules, organized within Exhibit CA-101, contain the revenue requirements calculations for HECO's 2005 Test Year. This Exhibit is jointly sponsored with other witnesses testifying on behalf of the Consumer Advocate. The specific witness who is responsible for the proposed adjustments set forth on separate pages within Exhibit CA-101 is identified on the schedule. Throughout my testimony, I will refer to individual Consumer Advocate adjustments that I sponsor by indicating the Consumer Advocate "Accounting Schedule" or the "CA Adjustment Schedule" that corresponds to the testimony discussion.

An index appears as the first page of CA-101, which lists each Accounting Schedule with a brief description of the adjustments or other calculations contained in the Schedule. These Consumer Advocate Accounting Schedules are organized into sections, within the following overall framework:

- Schedule/Section A — Summary of Revenue Requirement
- Schedule/Section B — Rate Base and Rate Base Adjustments
- Schedule/Section C — Operating Income and Adjustments
- Schedule/Section D — Cost of Capital Summary (CA T-4)
- Schedule E — Reconciliation of CA and HECO filings

Within Sections B and C, individual Consumer Advocate accounting adjustments are set forth on separate Accounting Schedules in sequential order, such that Schedule B-1, Schedule B-2, etc. represent proposed rate base adjustments and Schedule C-1, Schedule C-2, etc. represent proposed income statement adjustments. Consumer Advocate Accounting Schedule B and Schedule C start with the Company's prefiled rate base and operating income positions, respectively, and then reflect the total adjustments proposed by the Consumer Advocate to derive the Consumer Advocate's proposed rate base and operating income recommendations.

Individual rate base adjustments sponsored by Consumer Advocate witnesses will be referenced as either "Schedule B-xx" or as "Adjustment B-xx" to indicate the corresponding Consumer Advocate Accounting Schedule where the adjustment calculations are presented. Similarly, specific operating income adjustments sponsored by Consumer Advocate witnesses will be referenced as either "Schedule C-xx" or as "Adjustment C-xx" to indicate the corresponding Consumer Advocate Accounting Schedule where the adjustment calculations are presented. Mr. Steven Carver (CA-T-2) sponsors many of the accounting schedules within Exhibit CA-101.

Mr. David Parcell (CA-T-4) is responsible for the Consumer Advocate's proposed overall cost of capital, as summarized at Accounting Schedule D and on line 4 of Revenue Requirement Schedule A. Mr. Joseph Herz (CA-T-3) is responsible for the energy cost calculations that underlie the fuel and purchased power adjustments and the proposed Energy Cost Adjustment Clause ("ECAC") rate used in CA Accounting Schedule C-4, as well as the fuel inventory recommendations summarized within CA Accounting Schedule B-8.

II. OVERALL REVENUE REQUIREMENT.

Q. WHAT IS THE CONSUMER ADVOCATE'S PROPOSED REVENUE REQUIREMENT FOR THE 2005 TEST YEAR?

A. Based on the analysis conducted by all of the Consumer Advocate's witnesses, HECO's total rates and revenues should be increased by $23.5 million, as set forth at line 9 in the "CA PROPOSED" column of Accounting Schedule A. This proposed revenue increase is based upon the Consumer Advocate's proposed cost of capital that is sponsored by Mr. David Parcell (CA-T-4) and incorporates numerous other rate base and operating income adjustments sponsored either by Mr. Herz (CA-T-3), Mr. Carver (CA-T-2) or as explained herein, by me.

Q. WHAT IS THE ORIGIN OF THE BEGINNING VALUES USED IN THE CONSUMER ADVOCATE ACCOUNTING SCHEDULES?

A. Exhibit CA-101 uses the Company's prefiled exhibits, as summarized in Exhibits HECO-1901 (Rate Base) and HECO-2301 (Results of Operations) sponsored by Ms. Ohashi and Mr. Bonnet, respectively, as the beginning values for revenue requirement calculations. From these beginning points, each Consumer Advocate adjustment set forth on the Schedules labeled B-xx and C-xx represent a reconciling difference between the Company's position and the recommendations of the Consumer Advocate. A one-page summary listing and reconciling the many Consumer Advocate rate base and operating income differences to the Company's filing is set forth in Schedule E within the CA Accounting Schedules. The approximate revenue requirement "value" of the difference associated with the cost of capital recommendation is also set forth at the top of Schedule E.

Q. WHAT ARE THE MAJOR ISSUES CONTRIBUTING TO THE MUCH LOWER REVENUE REQUIREMENT THAT IS RECOMMENDED BY THE CONSUMER ADVOCATE, RELATIVE TO HECO'S PROPOSED INCREASE OF $98.6 MILLION?

A. The single largest issue is the removal of HECO's proposed base rate recovery of an estimated amount of Demand Side Management ("DSM") and related costs for separate consideration in an Energy Efficiency Docket, as ordered by the Commission in Order No. 21698 dated March 16, 2005, and as more fully addressed in Mr. Carver's testimony. A summary of the largest revenue requirement issues include:

REVENUE REQUIREMENT ISSUE	EXH. CA-101 REFERENCE	APPROXIMATE ISSUE VALUE $ MILLIONS
Removal of DSM Base Rate Recovery	C-17	$33.9
Recommended Cost of Capital	D	25.2
Pension Asset Rate Base Exclusion	B-10	7.1
Production O&M Expenses	C-8, C-9	3.5
Energy Costs and ECAC	C-4	2.8

Q. HOW IS THE BALANCE OF YOUR REVENUE REQUIREMENT TESTIMONY ORGANIZED?

A. Each topic or Consumer Advocate proposed adjustment that I sponsor is set forth in a separate section of testimony, as outlined in the Table of Contents set forth above.

Q. HOW DOES THE CONSUMER ADVOCATE PROPOSE THAT ITS REVENUE REQUIREMENT BE IMPLEMENTED, WITH RESPECT TO DISTRIBUTION AMONG RATE CLASSES AND RATE DESIGN?

A. I will respond to the Company's cost of service studies and rate design recommendations and will propose class distribution and rate design principles in a separately submitted Direct Testimony that has been identified as CA T-5.

III. <u>TEST YEAR CONCEPT</u>.

Q. WHAT IS THE PURPOSE OF A "TEST YEAR" WITHIN THE CONTEXT OF UTILITY RATE CASE PROCEEDINGS?

A. A test year is a period of time, usually including 12 contiguous months, that is adopted by a regulator to measure and compare the various data elements used to determine revenue requirement. It is common for the term "test year" to be used synonymously with the term "test period," and these terms have the same meaning in my testimony. The test year/period is used to populate the ratemaking formula, which consists of the following elements:

(<u>Rate Base</u> x <u>Rate of Return</u>) + <u>Expenses</u> = <u>Revenue Requirement</u>,

then

<u>Revenue Requirement</u> – <u>Present Revenues</u> = <u>Rate Increase (Decrease)</u>

The inputs to the formula are: "Rate Base," a measure of the amount of capital invested in the business; a required "Rate of Return" expressed as a percentage earnings requirement on the rate base; "Expenses," including operations, maintenance, depreciation and taxes; and "Present Revenues." The assembly of HECO's revenue requirement, combining each element of this formula, can be observed within CA Accounting Schedules A, B and C. It is critically important that representative values be determined for each of the key elements of the revenue requirements, the "Rate Base," "Rate of Return," "Expenses" and "Present Revenues" to reasonably determine the amount of required rate and revenue change. Reasonableness in the determination of revenue requirement also requires that each element be comparable, which means that a uniform test period concept must be employed so that each element of the revenue requirement is properly matched.

Q. SHOULD A TEST YEAR BE REFLECTIVE OF THE PRECISE AMOUNTS OF COSTS LIKELY TO BE INCURRED DURING THE FUTURE YEARS WHEN NEW RATES WILL BE IN EFFECT?

A. No. Ratemaking is a periodic exercise, rather than a continuous process. The test year is not intended to accurately predict the future results of a utility.

Each data element used to determine the revenue requirement is dynamic through time and can be expected to vary throughout the period the newly set utility rates remain in effect. For a growing electric utility, future sales and revenues, future expenses and future rate base investment levels will all likely, though not always, be larger in nominal terms. The use of a test year to quantify ratemaking values for these variables is intended to determine a revenue requirement based upon the relationship between revenue and cost levels at a common point in time, rather than the absolute values of test year revenues and costs. What is more important than absolute precision in ratemaking is that representative levels of ongoing revenues and costs are captured in a balanced way, within a consistently applied test year approach. Then, if future growth trends in revenues and costs prove to be somewhat offsetting, the approved rate levels will provide a reasonable opportunity for the utility to earn a fair return on investment.

Q. DO REGULATORY AGENCIES ALL EMPLOY THE SAME TYPE OF TEST YEAR?

A. No. Most regulatory jurisdictions use actual, historical test year data in rate case proceedings, while other states such as Hawaii employ projected or "future" test years. There is nothing inherently better about projected/future test years, relative to actual/historical test years, because the revenue change result being calculated is the result of relationships between the data elements, rather than the absolute value of revenues, expenses or rate base. For instance, if a utility is experiencing continually growing sales and revenues at the same time its rate base investment is growing and/or its expenses are growing, it may not be necessary to change rate levels – so long as revenue growth is sufficient to offset growing costs. This relative balance has apparently existed for HECO for some time, since the Company has not required an overall revenue increase since Docket No. 7766, in which a 1995 test year was employed.

Q. WHAT MUST BE DONE IF A TEST YEAR CONTAINS UNUSUAL OR EXTRAORDINARY LEVELS OF REVENUES OR COSTS?

A. If unusual or extraordinary revenue, expense or rate base amounts occur within the test year, it is essential that adjustments be made to "normalize" such amounts so that revenue requirement measurements are based upon only normal, ongoing amounts that are representative of financial performance within the test year. If such normalization is not performed, utility rates may be set to continuously over or under-recover ongoing cost levels to the disadvantage of either ratepayers or shareholders. Notably, HECO has made several "normalization" adjustments in its filing.[1]

[1] For example, HECO-617 reflects adjustments to "normalize" test year projected Emissions Fees and Ellipse software costs. Similar normalization adjustments are sponsored by other HECO witnesses.

Q. IS THERE ANOTHER CHARACTERISTIC OF THE TEST YEAR THAT IS IMPORTANT TO CONSIDER WITHIN RATE CASE PROCEEDINGS?

A. Yes. A test year can be based upon either <u>average</u> rate base compared to operating income statement reflecting average prices and volumes for the test year – or it can be based upon <u>year-end</u> rate base balances compared to year-end customer and sales/revenue levels, year-end employee headcounts and wage rates, year-end depreciation expenses, etc.

Q. PLEASE DESCRIBE THE TEST YEAR THAT HAS BEEN EMPLOYED BY HECO TO DETERMINE ITS ASSERTED REVENUE REQUIREMENTS IN THIS DOCKET.

A. HECO has developed its rate case filing using a calendar 2005 projected test year. Of importance is the fact that HECO's proposed test year in this Docket is based upon average rate base, average customer and sales levels and, for the most part, average expenses. Unfortunately, HECO has departed from its otherwise internally consistent test year presentation in quantifying several elements of its revenue requirement and the Consumer Advocate is recommending adjustments to correct the imbalances that are created by such departures. HECO should not be allowed to select specific costs that are known to be increasing and annualize them at year-end, while not moving the rest of the ratemaking elements to a matched, year-end point in time.

Q. WHY SHOULD THE COMMISSION CARE ABOUT MIXING AVERAGE TEST YEAR VALUES WITH YEAR-END OR "ANNUALIZED" TEST YEAR VALUES?

A. If a party to a rate proceeding is allowed to measure test year values using inconsistent or mixed approaches, the resulting revenue requirement can be distorted in favor of that party. It is important that a consistent approach be used so that revenues, rate base and expenses are measured as of a common point or period of time (i.e., either an average approach or year-end/ annualized approach) so that the relationship between revenues and costs is not mis-matched.

For example, if the test year level of customers and KWH sales is measured at an average level throughout the test year, then any growth in sales volumes is quantified near the mid-point of the test year. In this Docket, HECO has quantified its projected customer levels and sales volumes in this way, assuming gradual sales and revenue growth throughout the year associated with serving the "2005 Test Year Average Monthly Number of Customers," as shown in HECO-210. A significantly higher level of customers, KWH sales and electric revenues would result **if** year-end customer levels were instead annualized, because of continuing growth in demand for electric services. HECO could be expected to object to any adjustment attempting to annualize sales at year-end to account for increased revenues from customers added throughout the last half of 2005 in the absence of corresponding adjustments to also employ year-end rate base and year-end expense levels. Notably, the Consumer Advocate is not proposing such a year-end revenue adjustment even though it is reasonable to expect that recent vigorous rates of growth in electric demand and HECO revenues will continue into the future.[2]

Q. IS HECO'S PROPOSED TEST YEAR RATE BASE CALCULATED AS AN AVERAGE OF THE INVESTMENT AT THE BEGINNING AND END OF THE 2005 TEST YEAR?

A. Yes. The Consumer Advocate has no objection to HECO's approach to rate base quantification, since the two-point average that is used is consistent with the average customer, sales and revenue measurement employed by HECO witness T-2, Ms. Hazama.

Q. WHERE HAS HECO DEPARTED FROM CONSISTENT APPLICATION OF AN AVERAGE RATE BASE APPROACH?

A. The Company has prepared its test year labor expense projections assuming that the large number of new employee positions that were budgeted to be added during the year would actually cause the incurrence of labor costs throughout the entire year. Essentially, HECO has annualized labor expenses at year-end in a test year revenue requirement that is otherwise quantified

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2 See for example HECO-WP-201, page 15, where sales volumes are projected to grow throughout the 2006 through 2009 time frame.

using an averaging approach. Mr. Carver and I discuss this problem in greater detail and sponsor ratemaking adjustments to restate to an average complement of employees, making labor costs consistent with the average test year rate base and revenue levels.

In another departure from a consistently applied average test year, HECO has asserted, in response to Consumer Advocate information requests,[3] a desire to increase test year expenses and rate base to account for the estimated annualized costs associated with adding supplemental diesel generating resources at substations in October and November of 2005, as if those new costs had been incurred throughout the 2005 test year. The Consumer Advocate objects to this proposed annualization treatment, because it is inconsistent with the average test year approach, and will instead include such estimated capacity addition costs on an average basis as more fully described herein.

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3 HECO response to CA-IR-441 and May 5, 2005 HECO letter to Consumer Advocate and DOD regarding "updates" at Attachment 1A.

Q. IF KNOWN INCREASES IN COST OCCUR NEAR THE END OF THE TEST YEAR, IS IT NOT NECESSARY TO ANNUALIZE THE COSTS FOR A FULL YEAR FOR FULL COST RECOVERY TO BE POSSIBLE WITHIN THE NEWLY AUTHORIZED UTILITY RATES?

A. No. This is a commonly held misconception about the ratemaking process. There are expected to be significant increases in revenues after the mid-point of the average 2005 test year that may be more than sufficient to offset increasing future costs, such as the costs of adding new employees or the costs of increasing generating capacity to meet demand growth. It is important to resist the intuitive arguments to simply "fold in" known cost increases when there has been no corresponding effort to also account for demand and revenue growth that is expected to occur after the mid-point of the average test year.

As a point of reference, each one percent increase in HECO electric sales volumes would contribute more than five million dollars in additional gross margin (revenues less energy costs) that is available to help "pay for" increasing rate base or higher expenses.[4] Significant load growth is anticipated to continue into the future, providing additional revenues that

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[4] Test year sales revenues at present rates of $994 million, less fuel and purchased energy costs of $478 million equals margin revenues of approximately $516 million. One percent growth in sales would therefore produce about $5.1 million in pretax profit margin that is available to offset increasing costs. Such margin growth would be higher at proposed rates, after implementing the rate increase requested in this Docket.

HECO can use to pay for increasing costs not explicitly included in the test year.

Q. IS THERE A DIFFERENCE BETWEEN "NORMALIZING" ANY SPECIFIC REVENUE OR EXPENSE ELEMENT, IN CONTRAST TO "ANNUALIZING" THAT ELEMENT?

A. Yes. Normalizing entails the removal of an abnormality. For example, if projected test year expenses include an abnormally high expenditure level associated with power plant maintenance activity, it would be appropriate to "normalize" the cost of the maintenance work activity to a more representative, ongoing cost level for this element of the revenue requirement. If not normalized, inclusion of excessively high or low test period costs would create an over or under-recovery of such costs in future periods when more normal cost levels are expected to be incurred.

Annualizing, in contrast, involves translation of transaction data at a single point in time into a full annual year equivalent "annualized' amount. For example, if the Company projects the addition of ten new employees in December of the calendar test year and desired inclusion of a full year of salary and benefit expenses for the ten new employees, it could factor-up the monthly expense data for the ten employees to include the new costs for a full year with an annualization adjustment. As another example, as demand for electricity continues to grow and HECO adds several hundred new customers between the mid-point and the end of the test year, such growth cannot be considered abnormal. If an adjustment were made to fully consider sales and revenue levels at year-end, including the higher number of customers than is considered within the "average" level included in the Company's filing, that adjustment would be also be an "annualization" adjustment. Annualization adjustments have the effect of transforming the point in time when test year measurement is performed, from an average approach to a year-end approach.

Q. HOW HAS THE CONSUMER ADVOCATE TREATED ISSUES INVOLVING UTILIZATION OF AN AVERAGE VERSUS ANNUALIZED TEST YEAR IN THIS DOCKET?

A. In a word, such changes have been treated consistently. Mr. Carver and I have maintained the basic average test year concept throughout our adjustments, so as to avoid piecemeal distortions in the revenue requirement determination that can occur if individual elements of the revenue requirement formula are selected for annualization treatment, while other elements are not similarly annualized. Sales and revenues, rate base, staffing levels and operating expenses are all quantified throughout the entire 2005 test year on an average basis, so as to properly match all elements in determining the revenue requirement.

IV. **SALES REVENUES**.

Q. HOW DID HECO DEVELOP ITS TEST YEAR 2005 SALES AND REVENUE PROJECTIONS?

A. HECO T-2, Ms. Hazama describes in detail the process through which residential and commercial sales volumes are projected. For residential Rate Schedule R customers, a normalized usage per customer is derived from econometric modeling that is applied to projected average numbers of residential customers expected to be served throughout 2005, based upon HECO's market analysis of residential housing market.[5] For commercial customers, who are served on Rate Schedules G, H, J and P, HECO performed a "sector analysis" to evaluate and estimate anticipated demand levels across each segment of the commercial electricity market it serves.[6] Street Lighting sales on Rate Schedule F were projected based upon recent historical trends and the economic outlook for Oahu.[7] The results of HECO sales projections are summarized in HECO-201 through HECO-215.

The kilowatthour sales projections sponsored by Ms. Hazama in HECO T-2 are then priced out to derive sales revenue values at present and proposed rates by Mr. Young (HECO T-3), using certain assumptions about the distribution of projected test year 2005 sales volumes and customer levels

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5 See HECO T-2, pages 19-24, HECO-WP-201 and CA-IR-24.

6 See HECO T-2, pages 24-31 and HECO-WP-201.

7 HECO T-2, page 31, 32.

among the specific rate schedule demand and energy blocks, rate riders and other tariff provisions.

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE SALES VOLUME PROJECTIONS SPONSORED BY HECO T-2?

A. No. While it appears that HECO's forecast for 2005 has understated Residential sales volumes and overstated Commercial sales volumes in approximately offsetting amounts, the overall sales forecast appears reasonable and has been accepted by the Consumer Advocate. However, the Company has advised the Consumer Advocate that removal of new Demand Side Management ("DSM"), Combined Heat and Power ("CHP") and Economic Development Rate ("EDR") Rider initiatives from consideration in the rate case will change the projected test year sales volumes slightly, because HECO had included estimated sales impacts of future DSM, CHP and EDR in determining 2005 projected sales volumes. The KWH sales volume impact of this Company update was provided in the Company's May 5, 2005 letter summarizing known changes to the rate filing, within Attachment 1.

Q. WHAT IS THE REVENUE IMPACT OF SALES VOLUME CHANGES ASSOCIATED WITH THE REMOVAL OF NEW DSM PROGRAM, COMBINED HEAT & POWER AND ECONOMIC DEVELOPMENT RIDER EFFECTS FROM THE RATE CASE?

A. CA Accounting Schedule C-1 sets for the estimated sales revenue impact of the removal of the DSM, CHP and EDR impacts upon the test year sales forecast. The revenue per MWH values used in this calculation were derived from Mr. Young's (HECO T-3) calculations for each rate schedule, as reflected in Exhibit HECO-304 at pages 1 through 8. A corresponding Energy Cost Adjustment Clause ("ECAC") impact resulting from this modest sales volume change is incorporated within CA Adjustment Schedule C-4, because of differences in the Consumer Advocate's production simulation calculations, as sponsored by Mr. Herz, in contrast to HECO's calculations of test year ECAC includable energy costs that are included in the Exhibit HECO-304 revenue calculations.

Q. IS THERE A FUEL AND PURCHASED POWER COST IMPACT ASSOCIATED WITH THE SALES VOLUME ADJUSTMENT AT CA SCHEDULE C-1?

A. Yes. The test year fuel and purchased power expenses are embedded within CA Adjustment Schedule C-4

Q. DOES THE CONSUMER ADVOCATE DISPUTE ANY OF HECO'S SALES REVENUE CALCULATIONS BECAUSE OF PRICING ISSUES, RATHER THAN SALES VOLUME ISSUES?

A. Yes. In a number of instances, HECO has included downward revenue adjustments to estimate pricing discounts for customer participation in the various tariff rider provisions for HECO service that is provided on an Interruptible Contract basis (Rider I), for Off-peak and Curtailable Service (Rider M), for Time of Day Service (Rider T) and on an Economic Development Rate (Rider EDR). While many of these Rider service arrangements are representative of existing customer arrangements, HECO has also speculated in its filing that some new Rider arrangements may also develop in 2005 to further reduce test year revenues. Only one of these arrangements has materialized, to-date.

CA Adjustment Schedules C-2 has the effect of "re-pricing" projected sales made to certain HECO customers that were assumed to receive reduced-price service under tariff Rider provisions. The first line of CA Adjustment Schedule C-2 removes the revenue reduction impact of one assumed EDR schedule customer that HECO has assumed to exist during the test period. HECO has consented to the termination of its EDR rate schedule in response to CA-IR-584 and removal of this tariff requires an adjustment to eliminate assumed test period revenue impacts associated with EDR activity.

The second pricing adjustment is set forth at lines 2 through 11 of CA Adjustment Schedule C-2. This adjustment relates to assumed new "Potential Rider" customers that have not existed historically. HECO witness T-3 has assumed that certain unspecified customers will commence taking service under various Rider provisions of the Company's tariffs, resulting in lower revenues than are produced under standard tariff rates. The Consumer Advocate's revenue adjustment has the effect of increasing revenues to reflect "repricing" of sales, so as to remove the speculative lost revenue impact of assumed Rider customers that do not exist.

In its response to CA-IR-584, HECO stated, "There is an additional Rider M customer (Schedule J), acquired in April 2005, that will also be included in the revised 2005 test year estimates." Therefore, in the Consumer Advocate adjustment, an allowance is made for this new actual Rider M customer on Schedule J, by adding back an allowance for one assumed Rider M discount at line 10 of Schedule C-2, assuming the revenue effects of this new customer's participation will be approximately equal to the estimated values used by HECO for "potential" customers on Schedule J. Notably, in the same CA-IR-584 response, HECO claims, "The other potential rider customers identified in subpart (a) of this response, three Rider M customers and three Rider I customers, and their associated revenue impacts, will continue to be reflected in the estimate of test year revenues." The Consumer Advocate has removed the lost revenue impact of these "other potential rider customers" because such lost revenues are not sufficiently known and measurable to be included in determining revenue requirement. However, in the event HECO produces evidence of actual Rider participation by new customers in its rebuttal evidence, further refinement of this adjustment may be appropriate.

Q. WHAT IS THE POWER FACTOR CORRECTION AND HOW IS IT TREATED IN THE COMPANY'S REVENUE CALCULATIONS?

A. The power factor correction is a billing adjustment applicable to commercial customers that have "reactive" load characteristics that reduce the efficiency of HECO's power supply resources. Mr. Herz (CA T-3) describes in his testimony the engineering aspects of power factor correction. In its test period revenue estimates, HECO witness T-3 made certain assumptions about power factor billing demands that have the effect of understating revenues.

In response to CA-IR-532, the Company admitted that its assumed average power factor of 99% for the Schedule PP customers is overstated, "...due to an error in the extract program used to extract the rkvah from the billing records in ACCESS, which inadvertently was not recording and reporting the data from the var history files in ACCESS. The 95% power factor recorded for 2003 and 2004 will be used as the power factor adjustment for the test year estimate in rebuttal testimony."

Q. HAVE YOU RECALCULATED THE RATE SCHEDULE PP POWER FACTOR BILLING CREDITS TO CORRECT FOR THIS ERROR?

A. Yes. CA Adjustment Schedule C-3 increases revenues at present rates to reflect lower rate credits to Rate Schedule PP customers for power factor billing adjustments.

Q. WHAT IS THE PURPOSE OF THE ADJUSTMENT AT CA SCHEDULE C-4 FOR ECAC REVENUES?

A. In its filing, HECO's adjusted sales revenues at present rates included ECAC revenues calculated at 2.586 cents per KWH.[8] This pro-forma ECAC rate was derived from the Company's fuel and energy cost simulation calculations, so as to synchronize energy costs with ECAC revenues at present rates.

CA Adjustment Schedule C-4 recalculates the ECAC revenues in the Consumer Advocate's revenue requirement presentation using a modified ECAC factor of 5.789 cents per KWH that is associated with the revised higher energy costs calculated by Mr. Herz at Exhibit CA-314. This adjustment is necessary to properly synchronize the Consumer Advocate's calculated fuel and purchase power costs with the energy cost adjustment revenues that would be recoverable through the ECAC at such higher incurred cost levels. The related fuel and purchased power adjustments are discussed in a subsequent section of my testimony.

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8 See HECO-304 at "Fuel Oil Adjustment" under "Present Rates".

V. MISCELLANEOUS REVENUES.

Q. WHAT IS INCLUDED IN HECO'S MISCELLANEOUS REVENUES FOR THE TEST YEAR?

A. Miscellaneous Revenues include various types of Non-sales Electric Utility revenues collected from customers for late payment charges, service establishment charges, returned check charges and other tariff terms and conditions, as summarized in the top half of HECO-303. Also included in Miscellaneous Revenues are rent revenues and certain amortization amounts arising from Gains on Sale of property previously reviewed and ruled upon by the Commission, as summarized in HECO-1320 and HECO-303.

Q. IS ANY ADJUSTMENT NECESSARY FOR HECO'S PROPOSED TEST YEAR MISCELLANEOUS REVENUES?

A. Yes. CA Adjustment Schedule C-5 sets forth an adjustment for the Gain on Sale of Land amounts in HECO-1320, so as to remove $4,817 associated with the Lilipuna transaction, for which amortization was completed in May of 2005, and to increase the annual amortization associated with Iolani Court Plaza from $34,386 to $66,647 for additional units sold that increase the amortizable gain amount.[9] These adjustments are proposed to ensure that HECO's revenue requirement calculation provides for credits to customers of gains on sales in amounts as close as possible to the intent of previous Commission

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[9] Revised Iolani Court amounts are set forth in CA-IR-332, page 3 and CA-IR-372.

orders addressing the gains, while removing amortization amounts that are expiring and will not continue while new rates are in effect.

VI. COMBINED HEAT & POWER.

Q. WHAT IS COMBINED HEAT & POWER TECHNOLOGY?

A. Combined Heat & Power ("CHP") technology involves the installation of facilities at a customer's location to simultaneously generate electricity, while also meeting the need for on-site thermal demands for heating and cooling by directing the waste heat from the generation process through a heat exchanger or absorption chiller. CHP can be attractive as a type of distributed generation in situations where it is possible to economically satisfy combined thermal and electricity demands. HECO witness T-7, Mr. Seu describes CHP technology and the Company's plans for the deployment of CHP. In addition, Mr. Seu discusses the Commission's decision to suspend consideration of HECO's CHP proposal (i.e., Order No. 20831, issued March 2, 2004 in Docket No. 03-0366) while Distributed Generation is evaluated in Docket No. 03-0371, rather than consolidate both dockets.[10]

[10] Additional information regarding HECO's CHP program is contained in responses to CA-IR-568 and DOD/HECO-IR-3-42.

Q. DID HECO INCLUDE CERTAIN ESTIMATED REVENUE AND EXPENSE ADJUSTMENTS ASSOCIATED WITH PROJECTED OPERATIONS OF CERTAIN CHP PROJECTS IN THE 2005 TEST YEAR?

A. Yes. According to HECO-701, revenue adjustments totaling $134,300, fuel expense of $983,700, O&M Expenses of $219,900, and depreciation expense of $4,000 were incorporated into the test year forecast to account for anticipated CHP activity. In addition, test year capital additions for HECO investment in CHP totaling about $9.9 million were also recognized.

Q. WHAT SHOULD BE DONE WITH THE ESTIMATED REVENUE AND EXPENSE ADJUSTMENTS FOR CHP IN THE COMPANY'S RATE CASE FILING?

A. Adjustments are required to eliminate the effects of projected installation and operation of the CHP projects discussed by Mr. Seu. HECO's planned participation in CHP markets has not occurred as planned, due in part to regulatory consideration of the broader Distributed Generation issues before CHP Applications are considered. In its May 5, 2005 letter to the Consumer Advocate and Department of Defense ("DOD"), HECO has consented to the removal of CHP impacts from the rate case test year projections.

Q. PLEASE IDENTIFY THE CONSUMER ADVOCATE ADJUSTMENTS BEING MADE TO REMOVE CHP PROJECT REVENUES AND COSTS FROM THE COMPANY'S ASSERTED REVENUE REQUIREMENT.

A. Elimination of HECO's proposed CHP-related test year revenues and expenses are set forth in CA Adjustment Schedule C-6. Elimination of the corresponding rate base investment in Plant in Service is contained in CA Adjustment Schedule B-3. Mr. Herz has also removed the anticipated CHP resources from calculations supportive of the Consumer Advocate's recommended fuel and purchased energy costs and ECAC rates.

VII. <u>DISTRIBUTED GENERATION</u>.

Q. ASIDE FROM THE CHP PROJECTS DISCUSSED IN THE IMMEDIATELY PRECEDING SECTION OF YOUR TESTIMONY, DID HECO INCLUDE ANY COSTS ASSOCIATED WITH ITS PLANNED NEW INVESTMENT IN DISTRIBUTED GENERATION ("DG") IN ITS TEST YEAR FORECAST?

A. No, the addition of other DG resources was <u>not</u> included in HECO's prefiled rate case evidence. However, in response to CA-IR-441 and in a letter to the Consumer Advocate and DOD dated May 5, 2005 describing certain test year updates the Company intends to recognize ("May 5 Update Letter"), HECO stated its desire to "Revise for the inclusion of normalized expense for HECO-leased DG units at HECO substations (see response to CA-IR-441)." Attachment 1A to the May 5 Update Letter described the substitution of

DG technology for the suspended CHP projects, HECO's activities associated with design, selection and cost estimation for DG; and the anticipated capital investment and expenses associated with installing a total of nine rented DG units at three HECO substation sites (3 sites with 3 units each). According to Attachment 1A at page 2, "HECO anticipates the first of the three site installations in October 2005. The second and third site installations are projected to be installed in November 2005. HECO proposes to normalize the impact of operations and maintenance ("O&M") expenses by including the annual O&M expenses for the nine units in expenses for the 2005 test year."

Q. WHAT DOES HECO MEAN IN PROPOSING TO "NORMALIZE" O&M EXPENSES FOR THE NEW DG UNITS BEING ADDED IN OCTOBER AND NOVEMBER?

A. HECO actually intends to "annualize" the O&M costs for the new DG capacity <u>as if it had been installed throughout the entire test year</u>. The Commission is asked to ignore the fact that under present plans the new capacity will not be added until just before year-end and instead assume that a full year's expenses are includable in the 2005 average test year.

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE ANNUALIZATION OF THE PROPOSED NEW DISTRIBUTED GENERATION RESOURCES IN CALCULATING THE COMPANY'S TEST YEAR REVENUE REQUIREMENT?

A. Yes. If included at all, the DG unit costs should only be included in the test year on an average basis, with no annualization of costs as proposed by HECO. The importance of maintaining consistency with the average test year was described earlier in my testimony. It would be patently unfair to ratepayers to annualize capacity additions required to meet growing demand levels, while not also annualizing the demand growth itself, which would yield much higher year-end annualized sales revenue levels.

Q. PLEASE DESCRIBE THE CONSUMER ADVOCATE ADJUSTMENTS MADE TO ACCOUNT FOR THE NEW DISTRIBUTED GENERATION RESOURCES ON A BASIS CONSISTENT WITH THE AVERAGE 2005 TEST YEAR.

A. Consumer Advocate Adjustment Schedule B-4 includes projected capital expenditures associated with the DG units in the year-end data point for 2005 average rate base calculations, effectively including one-half of such costs for the full test year rate base. An allowance for fuel inventory for the DG units is not included as part of this adjustment, but is separately provided for as part of overall fuel inventory within CA Adjustment Schedule B-8.

Adjustment Schedule C-7 provides for DG operation and maintenance expenses, including monthly rental payments on the new DG generating units, for only the months such units are expected to be operational in 2005. This treatment provides for cost recovery based upon the actual timing of installation of the DG units, recognizing that the added generating capacity is expected to be available only for the last few months of the test year.

Q. IF THE COSTS ASSOCIATED WITH THE NEW DG UNITS ARE NOT ANNUALIZED, AS PROPOSED BY HECO, WILL THE COMPANY BE DENIED FULL RECOVERY OF THE ONGOING COSTS OF THE UNITS IN 2006 AND LATER YEARS WHILE NEW UTILITY RATES ARE IN EFFECT?

A. No. As explained in the Test Year Concept portion of my testimony, HECO will be able to retain for its shareholders all benefits associated with continuously growing Oahu sales volumes and revenues occurring after the mid-point of the 2005 average test period. The new revenues from continuing load growth is available to offset costs associated with adding DG units to serve such growing loads. In fact, if HECO continues to add DG units in 2006 or is successful in gaining Commission approval and installing CHP capacity in the future, growing sales and revenues may prove sufficient to enable the Company to absorb such capacity costs without pursuing another rate case.

Q. DOES THE HISTORY OF HECO RATE PROCEEDINGS TEND TO VALIDATE THE CONCEPT YOU DESCRIBE, WHERE LOAD AND

REVENUE GROWTH BETWEEN RATE CASES CAN BE SUFFICIENT TO OFFSET COST INCREASES?

A. Yes. The fact that HECO has not required a general rate case since 1995 is an indication of the significant revenue benefits realized from sales growth between rate cases that can prove sufficient to offset increasing costs for very long periods of time.

Q. IN THE EVENT HECO IS UNABLE TO ACTUALLY INSTALL THE DG UNITS BY YEAR-END, WHAT SHOULD BE DONE WITH THE CONSUMER ADVOCATE ADJUSTMENTS SET FORTH AT ACCOUNTING SCHEDULES B-4 AND C-7?

A. If the new DG generating units are not completed and installed within the test year-end for any reason, the Consumer Advocate's adjustments should be rejected. This would have the effect of not charging ratepayers for the costs associated with new capacity that is not in service as of year-end.

VIII. FUEL AND PURCHASED POWER EXPENSE.

Q. HOW HAS HECO DETERMINED ITS PROPOSED FUEL AND PURCHASED POWER EXPENSES FOR RATEMAKING PURPOSES?

A. In its filing, the Company has calculated pro-forma fuel and purchased power expenses using a dispatch simulation program with input data associated with HECO generating units, fuel prices, purchase power contracts and adjusted demand levels. These calculations were reviewed by Consumer Advocate witness Mr. Joseph Herz and are addressed in detailed within CA-T-3.

Q. HOW ARE THE RESULTS OF MR. HERZ'S ANALYSIS INCORPORATED INTO THE CONSUMER ADVOCATE'S REVENUE REQUIREMENT?

A. CA Adjustment Schedule C-4 sets forth the ratemaking adjustments required to include adjusted fuel expense and purchased energy expenses based upon the analysis performed by Mr. Herz, as summarized in Exhibit CA-301. In Exhibit CA-314, Mr. Herz calculates the Energy Cost Adjustment Clause ("ECAC") factor that corresponds with the Consumer Advocate's test year fuel and purchased power expense levels, system heat rate and sales levels. This ECAC value is then used to calculate annualized fuel adjustment revenues at present rates which are incorporated into CA Adjustment Schedule C-4 at lines 8 through 16 to properly synchronize ECAC revenues and the related energy expenses for the test year, as referenced in my earlier testimony regarding Sales Revenues. Finally, lines 17 through 21 calculate the incremental revenue taxes associated with the additional ECAC revenues to be collected at the higher CA-proposed fuel and energy cost levels.

Q. AT PAGES 28 THROUGH 33 OF HIS TESTIMONY, MR. ALM TESTIFIES IN FAVOR OF CONTINUED UTILIZATION OF THE ECAC. IS THE

CONSUMER ADVOCATE IN AGREEMENT WITH HECO THAT THE ECAC SHOULD CONTINUE TO BE EMPLOYED?

A. Yes. Fuel price volatility in international fuel markets and HECO's dependence upon such markets makes ECAC continuation important to the Company and its ability to timely recover fluctuating costs thereby minimizing earnings volatility and the risk of reduced access to capital markets on reasonable terms. On the other hand, continued utilization of ECAC shifts virtually all energy cost risk onto ratepayers and the rate of return awarded by the Commission in this Docket should fully account for this energy cost risk distribution between shareholders and ratepayers.[11]

Q. DOES THE CONSUMER ADVOCATE OBJECT TO THE CONTINUATION OF THE ECAC TO PROVIDE HECO WITH RECOVERY OF CHANGES IN ENERGY COSTS?

A. No. However, it should be recognized that the ECAC effectively transfers operating risks associated with energy cost fluctuations to HECO's customers. When the ratemaking cost of equity capital to be allowed HECO is being considered, this transfer of commodity price risk exposure to customers should be found to directly reduce the business risk facing HECO and its shareholders. In addition, the Commission must remain vigilant in monitoring

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[11] In its response to DOD/HECO-IR-3-45, the Company acknowledges that its risk factor is directly impacted by continuation of ECAC, stating, "If ECAC were discontinued, the electric utilities' results of operations could fluctuate significantly as a result of increases and decreases in fuel oil and purchased energy prices."

HECO fuel procurement and operational performance because of the diminished financial incentives that result from automatic rate recovery of fuel price changes.

Q. IS ANY MODIFICATION TO HECO'S PROPOSED SALES HEAT RATE BEING PROPOSED BY THE CONSUMER ADVOCATE?

A. Yes, Mr. Herz is recommending that the Sales Heat Rate for future ECAC administration be revised, as shown in his Exhibit CA-306.

IX. PRODUCTION EXPENSE.

Q. BEYOND FUEL EXPENSES, ARE THERE OTHER EXPENSES ASSOCIATED WITH THE OPERATION OF THE COMPANY'S GENERATING UNITS?

A. Yes. There are the expenses to operate and maintain the Company's production facilities that are recorded in Production Operation and Production Maintenance expenses, ranging from NARUC Account Nos. 500 through 554. Significant Non-fuel Production Operations expenses are incurred for staffing and operating the Company's generating units located within HECO's Kahe, Waiau, and Honolulu power plants and for the engineering, environmental and other administrative functions supportive of such operations. Production Maintenance expenses primarily consist of the labor and non-labor costs incurred to repair and maintain generating units and related generating plant facilities. I will be discussing each of these expense projections in the following sections of my testimony.

A. PRODUCTION OPERATIONS EXPENSE.

Q. WHAT IS HECO'S ESTIMATED LEVEL OF PRODUCTION OPERATIONS EXPENSE FOR THE 2005 TEST YEAR?

A. As shown at HECO-615, HECO's estimated labor and non-labor Production Operations expenses for the 2005 test year amounts to $24,282,000.[12]

Q. HOW DOES HECO'S TEST YEAR PROJECTION COMPARE TO HISTORICAL EXPERIENCE FOR THIS EXPENSE ACCOUNT?

A. As shown in the following table, the Company's test year projection is considerably higher than comparable actual Production Operations expenses incurred historically.

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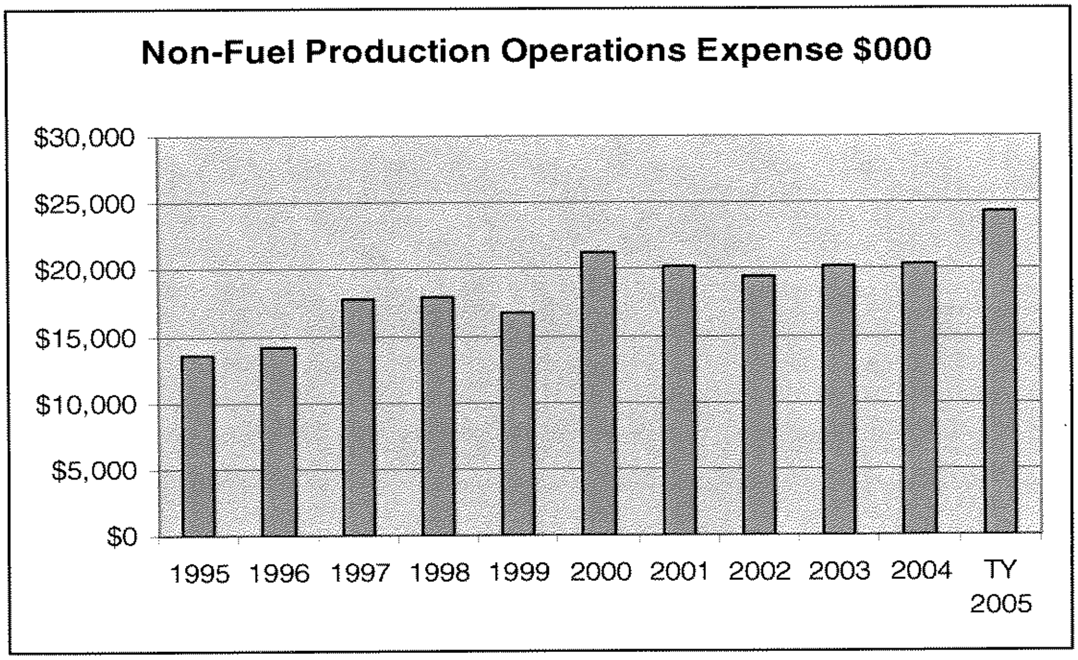
12 This amount is the test year "Operating Budget", before certain HECO-proposed adjustments.



Source: CA-IR-37, page 3.

From this historical information, spanning the years since HECO's last rate case test year, one can observe that Non-fuel Production Operations expenses have been fairly stable at around or below about $20 million per year for many recent years. This graph illustrates that the Company's projected 2005 expense levels reflect a significant increase in expenses and an abrupt end to the pattern of recently successful cost containment.

Q. SHOULD THE COMMISSION APPROVE HECO'S PROJECTED NON-FUEL PRODUCTION OPERATIONS EXPENSE LEVEL FOR THE 2005 TEST YEAR?

A. No. HECO's estimated costs are excessive, for the following reasons.

- HECO has notably done a good job of operating its fleet of generating units, achieving good unit availability and relatively stable expense levels in recent years and has provided no substantive documentation to support the claimed increase in expenses for the test year.
- HECO has not added any significant new generating capacity that would help to explain the projected large increase in test year operating expenses.[13]
- Projected labor costs are overstated, assuming many new employees are added in all 12 months of the test year.
- Specific non-labor expense elements are overstated, as described more fully herein.

Q. WHAT ARE THE PRIMARY TYPES OF COSTS DRIVING THE COMPANY'S PROJECTIONS OF MUCH HIGHER PRODUCTION OPERATIONS EXPENSE LEVELS THAN HAVE HISTORICALLY BEEN INCURRED?

A. Most of the large increase in Production Operation expenses being proposed by HECO can be isolated to more than \$2.1 million for increased staffing and high overtime hours (i.e., increased labor costs), and another \$1.6 million for

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13 As an update to its prefiled case, HECO has requested rate case recovery of nine new Distributed Generation units to be installed at substations. These new resources are not central station generation as exists at the Honolulu, Waiau or Kahe stations. Separate Consumer Advocate ratemaking adjustments are set forth at CA Adjustments Schedules B-4 and C-7 to properly account for test year Distributed Generation costs.

increased non-labor expenses, primarily involving outside services contractors (see HECO-618 and HECO-621).[14]

With respect to labor costs, HECO-618 shows that the increased staffing and overtime costs results in a test year labor projection that is 19 percent higher than the labor costs previously occurred to operate its fleet of generating units. These higher test year production operations labor costs are driven primarily by the assumption that staffing levels will be about 18 percent higher throughout the 2005 test year, as indicated in HECO-619.[15] Notably absent from this major staffing buildup is any significant reduction in HECO's historically high overtime rates, that are projected to continue in 2005 in spite of the large increase in workforce that is assumed.[16]

Regarding non-labor expenses, HECO has included in its test year projections significant increases in contractor charges for research and development, emission fees, environmental consulting costs, water purchase expenses and a variety of other materials and contractor charges.

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14 See HECO-615. This amount is per HECO's Operating Budget, before ratemaking adjustments totaling $(405,000), which produce a net proposed adjusted test year amount of $23,877,000. The pre-adjustment amount is used in testimony for meaningful comparison to prior years' unadjusted expenditure levels.

15 HECO proposes adding 22 new employees, relative to an existing work force of 124 at year-end 2003.

16 CA-IR-635 indicates 2005 Budget Overtime Hours exceed 100,000. Prior year's actual overtime hours in 2002, 2003 and 2004 ranged from 89,000 to 108,000 hours.

Q. HOW DOES THE COMPANY EXPLAIN THE LARGE CHANGE IN THE LEVEL OF PRODUCTION OPERATIONS EXPENSES THAT IT NOW PROJECTS?

A. Mr. Fujinaka (HECO T-6) sponsors HECO's much higher proposed Production O&M expenses, arguing that the "rapidly growing demand" contributes to the proposed higher production expenses," the "Age of generating units and associated infrastructure" contribute to higher expenses, and that "Environmental, Safety and other regulations" require more expenses to maintain compliance.[17]

Q. DOES MR. FUJINAKA EXPLAIN HOW HECO WAS ABLE TO OPERATE ITS UNITS EFFICIENTLY, AND AT A LOWER COST LEVEL IN THE RECENT PAST, BUT WILL NO LONGER BE ABLE TO DO SO WITHOUT THE MUCH HIGHER EXPENDITURES PROJECTED FOR THE TEST YEAR?

A. Not really. The explanations offered are the generalizations noted above. The only detailed explanations that are offered by Mr. Fujinaka can be found at HECO-629 and HECO-WP-601, where test year projected costs are compared to the year 2003 with "comments" explaining a few discrete cost changes. For the labor categories, the explanations given in HECO-WP-601 refer to "filling existing vacancies" and "increased staffing". For outside services non-labor

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17 T-6 at pages 8 through 10.

expenses (HECO-629), reference is made to environmental compliance costs, two large new R&D projects and various computer system costs.

Q. HOW VALID IS MR. FUJINAKA'S ARGUMENT THAT RAPID LOAD GROWTH DRIVES UP THE EXPENSES ASSOCIATED WITH OPERATING THE FLEET OF GENERATING UNITS?

A. This argument is highly questionable because non-fuel production operations expenses do not generally vary with changes in output of the generating units.[18] Thus, there is no support for HECO's claim that the load growth and increased operation of the generating units will result in the abrupt increase in such expenses that is now being proposed by HECO for the 2005 test year.

Q. PLEASE EXPLAIN WHY YOU CONTEND THAT INCREASED OUTPUT OF GENERATING UNITS DOES NOT TRANSLATE TO HIGHER EXPENSE LEVELS.

A. The cost to staff and operate a power plant is a relatively "fixed" cost that is incurred without much regard to the level of output actually produced by a generating unit. For instance, HECO must staff a power plant to operate the generation at that plant during all hours required in order to make available for

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[18] This argument has some validity with respect to maintenance costs, which are addressed in the next section of my testimony.

dispatch the entire capacity of the generating units.[19] The "fixed" nature of such costs is confirmed by HECO cost of service witness, Ms. Seese (HECO T-22) in the treatment of all non-fuel production operations expenses as a fixed "demand" cost, rather than a variable "energy" related cost.[20]

Q. WHAT IS THE SIGNIFICANCE OF THE FACT THAT HECO HAS NOT ADDED NEW GENERATING CAPACITY, GIVEN THE COMPANY'S PROJECTED LARGE INCREASE IN TEST YEAR PRODUCTION OPERATION EXPENSES?

A. Production operations expense tend to be largely fixed in relation to the installed fleet of generating units, such that large expense increases usually correspond with the addition of new generating capacity. However, the fleet of Company owned and operated generating units, as shown in HECO-601, has not changed since the Kahe 6 unit was added in 1981. Independent Power Producer capacity was added in the early 1990's, but the generating units that

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19 Certain non-labor operations expenses are variable with KWH output, such as water and water treatment chemicals, emission fees, lube oil and other consumable supplies. However, these are relatively small elements of HECO's proposed test period expenses and have been quantified to fully account for demand growth.

20 T-22 at page 10. See also HECO-WP-2202, page 30, where the "Production-Dmd" classification of all Production O&M Labor costs can be observed.

are staffed and operated by HECO personnel is unchanged.[21] Thus, there is no obvious reason for the projected abrupt increase in production operations costs to operate the same fleet of units in the 2005 test year.

Q. DOES THE AGING OF HECO GENERATING UNITS EXPLAIN WHY IT SHOULD COST MUCH MORE TO OPERATE THE UNITS IN 2005 THAN IN HISTORICAL YEARS?

A. No. First, to state the obvious, the units in HECO's generating fleet have been growing "old" gradually for many years. Yet, this gradual aging phenomenon has not produced the steady upward trend in operations expense levels that Mr. Fujinaka's argument would suggest. As noted in previous testimony, HECO non-fuel Production Operations expenses have been very stable throughout recent history at much lower levels than are projected for the test year. Moreover, HECO has consistently achieved better than industry average performance in its system-wide Equivalent Availability Factor and Equivalent Forced Outage Rate throughout recent history, as shown in HECO-602 and HECO-603, respectively, with much lower historical production operations expense levels than are now being proposed by HECO.

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21 The Consumer Advocate understands that HECO now intends to install and operate nine small diesel units at various substation locations starting in late 2005. See Footnote 13 and CA Adjustment Schedules B-4 and C-7. Incremental new costs associated with the installation and operation of these diesel units are separately considered in this testimony and are not part of the historical or test year projected costs being discussed at this point in testimony.

Q. DOES ANY HECO WITNESS OTHER THAN MR. FUJINAKA ADDRESS HECO EXPENSE LEVELS IN GENERAL AND THE COMPANY'S APPROACH TO PREPARING THE RATE CASE FORECAST?

A. Yes. Mr. Alm (HECO T-1) comments more broadly at page 19 of his testimony about how HECO has carefully managed costs <u>in the past</u>, but should not be expected to do so in the rate case forecasts. Regarding recent historical spending, he states:

- "HECO implemented staff caps and staffing levels were carefully monitored."
- "Vacancies were not automatically filled."
- "whenever the opportunity presented itself, HECO managed with less than was necessary in the long term."
- "HECO deliberately reduced spending, while not compromising reliability."

However, after explaining how costs have been successfully constrained in the recent past, Mr. Alm suggests that such cost constraining effort should <u>not</u> be expected during a rate case. He states at page 19, "From a ratemaking policy viewpoint, the rates should be representative of the future period when rates will be in effect. Even if the Company has not incurred expenses at the same level in prior years, if the expenses are reasonable they should be included for ratemaking purposes during the period when the rates are in effect."

Q. REGARDING MR. ALM'S TESTIMONY, DO YOU AGREE THAT COST CONTAINMENT SHOULD <u>NOT</u> BE EXPECTED OF HECO IN THE FUTURE?

A. No, I do not. The Commission's policy of utilizing projected test periods should not be treated as an opportunity to inflate test year expenses by ignoring historical and ongoing productivity achievements, relaxing cost control measures or by assuming the future employment of unconstrained staff levels or excessive overtime. Given today's high fuel price environment and the rate impacts through the ECAC combined with the significant increase in base rates being proposed, there is no better time than now to enhance and expand upon HECO's recently successful cost control measures that do not compromise the quality of electric services being provided.

A less important point of clarification is that test year O&M expenses need not be inflated for anticipated cost increases beyond 2005 to be reasonable "during the period when the rates are in effect" as suggested by Mr. Alm, because continuing revenue growth after 2005 can be expected to help offset any cost increases that may be experienced by HECO after 2005.

Q. DID THE CONSUMER ADVOCATE SEEK ADDITIONAL INFORMATION ABOUT HECO'S ABILITY TO DELIBERATELY CONSTRAIN ITS COSTS AND REDUCE SPENDING?

A. Yes. In an effort to evaluate whether HECO's historical ability to constrain hiring and spending has suddenly and irreversibly ended, several information requests were submitted by the Consumer Advocate.

In CA-IR-243, HECO was asked to provide "complete copies of Production Department budget variance reports that were prepared for reporting periods within the years 2003 and 2004, including full details regarding non-fuel O&M expenses, as well as all narrative reports explaining variances from budget levels." In response, HECO stated, "HECO objects to providing 'variance reports' on the basis stated in the objections and response to CA-IR-242."

In CA-IR-630, HECO was asked about Mr. Alm's testimony that stated in the past "HECO deliberately reduced spending, while not compromising reliability, during that period." In this information request, the Consumer Advocate asked specific questions seeking internal documentation of spending reduction instructions, reports to senior management and tracking of amounts saved. HECO objected to several of these questions and claimed that the Company "did not track spending reductions that were actually implemented." No documents were produced by HECO, even though a

Powerpoint presentation to the Board of Directors was referenced in part (h) of the response.

Finally, CA-IR-454 and CA-IR-539 were submitted on March 22 and April 5, in which HECO was asked to provide copies of its 2006 operating budget details and a detailed breakdown of the electric operating expenses contained in any multi-year long term financial forecasts it has prepared. This information was requested to compare the test year forecast against management's projections of expenses in 2006 and subsequent years. On June 10, many weeks after these questions were submitted, HECO objected to the requests and provided no responsive information.

Q. GIVEN THAT THIS TESTIMONY IS BEING FILED NEAR THE MIDDLE OF THE 2005 TEST YEAR, DID THE CONSUMER ADVOCATE SEEK DETAILED BUDGET VARIANCE REPORTS TO SEE IF HECO WAS CONTINUING TO MANAGE COSTS BELOW RATE CASE PROPOSED LEVELS?

A. Yes. In CA-IR-455, HECO was asked if it has "prepared any budget variance reports or other accounting reports that compare actual revenues, operating expenses and plant investment to forecasted amounts for year to date 2005." The Company responded, "yes," but then objected to providing such information "on the grounds stated in response to CA-IR-242." In the referenced "CA-IR-242," HECO denied similar information for the years 2002, 2003 and 2004, arguing that "internally distributed reports and narrative discussions of the reasons for the variances . . . are privileged and confidential and should not be provided on public policy grounds, as described below."

It should be noted that CA-IR-242 was submitted to HECO in early February, but the Company's objections were not submitted until mid-June, more than four months later on the eve of finalizing this testimony. HECO's tardy objections effectively precluded any ability to compel or analyze internally and candidly prepared, contemporaneous budget variance data prepared by management. However, at page 6 of the response to CA-IR-242, one can observe that HECO is actually tracking Power Supply costs against a reduced "Target Budget" that is lower than the original 2005 "Budget" included in the rate case filing, due largely to something captioned an "Even Hiring Lag."

Q. WHAT IS AN "EVEN HIRING LAG"?

A. That term is not defined in CA-IR-242, but in response to CA-IR-14 (submitted January 25 and answered on June 10), HECO states that after the 2005 budget was developed for the test year estimates, it was adjusted in formulating the "2005 operating budget" for a number of known changes, explained as including "a reduction of $3,649,000 for consideration of a lag in the hiring process for positions included in the updated 2005 budget (even with the lag, the 2005 year-end employee count is still assumed to be attained). The adjustment for the hiring lag started with a projected 2004 year-end employee count and assumed that positions would be filled evenly throughout 2005 to get to the year-end budgeted employee count. Since the budget reflected most positions being filled at the beginning of the year, the difference in monthly employee count resulted in lower costs and is referred to as the 'hiring lag adjustment'."

Q. WHAT IS THE IMPACT OF THE "EVEN HIRING LAG" ON THE PROJECTED 2005 OPERATING AND MAINTNENCE EXPENSE LEVELS?

A. As shown on page 5 of the response to CA-IR-14, the "Even Hiring Lag" on Company-wide 2005 O&M totals $3,693,762 and is quite significant in the context of consistency with the average test year that is employed to estimate revenues, rate base and other Non-labor expenses. The Production Department portion of the "Even Hiring Lag" is $2,002,611.[22] In my opinion, HECO should not be permitted to adopt a realistic 2005 operating budget for internal management purposes that assumes gradual hiring of new employees, while preparing hypothetical staffing estimates for the rate case that assume full employment of every new and existing position throughout all twelve months of the test year.

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[22] See page 6 of CA-IR-242.

Q. TURNING TO THE PROJECTIONS OF STAFFING, LABOR HOURS AND LABOR-RELATED EXPENSES WITHIN THE 2005 TEST YEAR FORECAST, WHAT PROBLEMS EXIST IN THE WAY HECO HAS ASSEMBLED ITS RATE CASE FORECAST?

A. Staffing of Production Operations functions is budgeted to increase during 2005 by 22 new positions, as shown on HECO-619. It is reasonable to expect a regulated company to produce some evidence of <u>need</u> for increased staffing. In addition, the regulated company should, at a minimum, provide a credible showing that all economic benefits associated with a larger work force have been fully recognized. For example, if fully implemented, such a large staffing increase should result in significant savings in the historically high overtime levels among operations personnel that are depicted in HECO-620. Additionally, if contractors have been used to augment overextended employees when staffing was lower, the costs of such contract service should be avoidable to some degree when staffing is increased.

Unfortunately, HECO has produced no economic studies supportive of its decision to dramatically expand the Production Department workforce by 22 positions. Furthermore, HECO has failed to account for avoidable overtime or contractor charges that should at least partially offset the cost of newly hired employees.

The specific problems associated with HECO's projected Production Operations labor and labor-related expenses include:

- Standard labor rates developed by HECO to develop labor cost forecasts are overstated, as more fully explained by Mr. Carver in CA-T-3.
- Staffing levels are overstated, because HECO assumed the projected new employee positions would be filled throughout the 2005 test year, when actual employment levels thus far in 2005 have been significantly lower than projected levels. HECO has ignored the "Even Hiring Lag" in assembling a higher rate case forecast than is being used as the official "operating budget" for 2005.[23]
- In assuming full employment of every budgeted position in its rate case forecast, the Company has ignored the reality of labor markets and turnover that cause certain positions to be vacant at any given time.
- Overtime hours and costs are overstated because HECO failed to reflect offsetting reductions in historically high overtime levels as a result of dramatically expanding staffing levels.

Each of these problems contributes to the overstatement of the labor elements of test year 2005 Production Operations expenses in the Company's filing.

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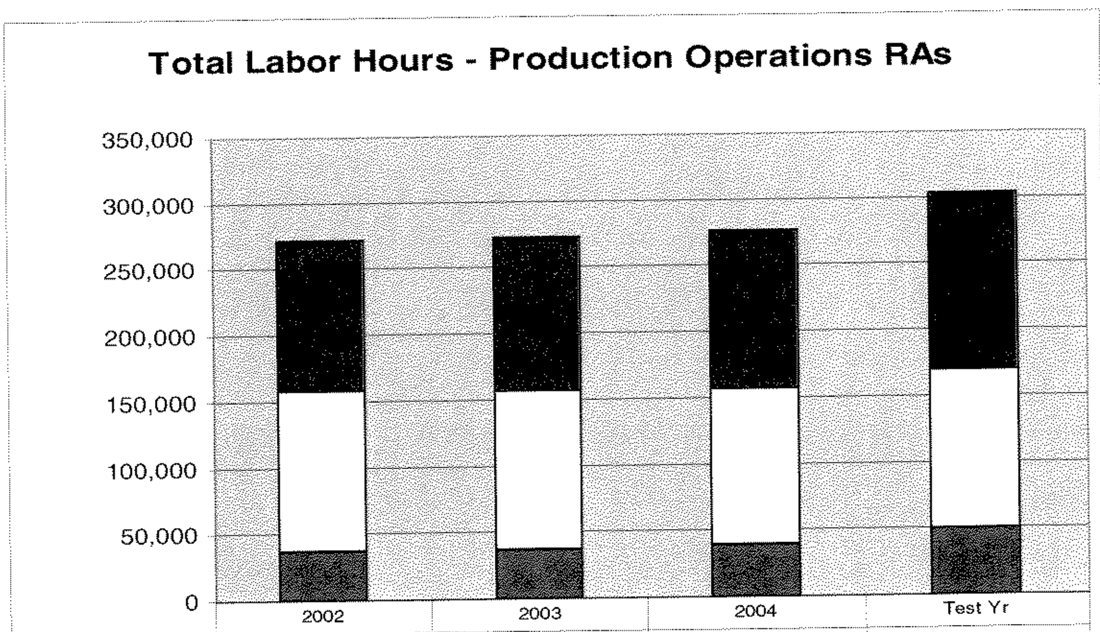
23 See CA-IR-14, CA-IR-242, and the prior discussion of "Even Hiring Lag" budget adjustments in this testimony.

Q. HOW DO THE TEST YEAR PRODUCTION OPERATIONS LABOR HOURS COMPARE WITH COMPARABLE LABOR HOURS DATA IN PREVIOUS YEARS?

A. The labor hours for the test period are inexplicably higher in the test year for all three HECO generating stations, Honolulu, Kahe and Waiau, as well as for the administration functions supporting Production Operations. As noted earlier, this is unusual given the fixed cost nature of operating expenses associated with an unchanged portfolio of generation resources. Total labor hours for the Operations Staff Responsibility Areas ("RAs") that charge expenses primarily to Production Operations compare as follows:



	2002	2003	2004	Test Yr
Waiau Stn Oper	113,533	115,825	119,453	133,992
Kahe Stn Oper	120,490	119,913	117,660	118,674
Honolulu Stn Oper	37,367	37,520	39,598	50,592

This chart illustrates the quite large increase in labor hours being projected by HECO for the test period, much of which can be attributed to planned around the clock "24 x 7" operator staffing at Waiau and Honolulu Stations.

Q. HAS THE COMPANY ADEQUATELY DEMONSTRATED THE NEED FOR THE 22 NEW PRODUCTION OPERATIONS EMPLOYEES THAT ARE INCLUDED IN HECO'S TEST YEAR LABOR FORECAST?

A. In my opinion, HECO has not fully explained why it needs to add so significantly to Production Operations staffing levels and labor hours. HECO operating personnel have performed well historically in operating a fleet of generating units that has not changed in terms of the number of units of installed capacity. When asked for its studies or analyses demonstrating the <u>need</u> for adding 22 positions to staffing, the Company responded to CA-IR-176 stating:

> a study was not necessary to determine the level of staffing required to increase availability of Honolulu Units 8 & 9 and Waiau Units 3 & 4, from 2 shifts, 5 days per week to 3 shifts, 7 days per week (24x7). The staffing levels were based on the types of operators required to man an extra shift at H8&9 and W3&4.

In its response to CA-IR-633, HECO stated:

> The increase in staffing is for the cycling units that are placed back in the commitment order when the reserve margin decreases such that the cycling units are needed for more than just the week days (which have higher loads than the weekend days). Therefore, the cycling duty mode of operation for W3, W4, H8 and H9 has not changed and the reserve margin has declined to the point where it is not practical to meet this

> operating requirement through overtime and additional staffing is now required.

According to the response to CA-IR-496, HECO claims:

> The increase in Operation expenses in 2005 compared to the past four years is attributed to an increase in operations staffing to fully utilize the capabilities of Honolulu Units 8 & 9 (H8&9), and Waiau Units 3 & 4 (W3&4). The additional staffing will increase availability of H8&9 and W3&4 from 16 hours per day, 5 days a week (16x5) to 24 hours per day, 7 days per week (24x7)."

Q. DO YOU AGREE THAT THERE IS A NEED FOR INCREASED STAFFING FOR THE HONOLULU AND WAIAU UNITS THAT ARE REFERENCED?

A. Yes, in spite of the absence of any formal studies, some need for increased operations staffing exists to reduce recent overtime levels. This can be seen in HECO-609 that shows there is an increasing recent trend in "Cycling Unit Service Hours," including utilization of the four units (H8, H9, W3 and W4) that are now planned for 24 x 7 staffing. In HECO-620, Mr. Fujinaka illustrates a recent increase in overtime percentages, particularly at the Honolulu and Waiau power plants where staffing is proposed to increase in the test year.

Thus, it would appear that some increased staffing is justified to reduce historically high overtime requirements. In fact, in 2004, overtime hours for Honolulu Station Operations (RA=PIH) was 9,489 hours and for Waiau Station Operations (RA=PIW) was 22,760 hours.[24] This level of recent actual

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[24] HECO response to CA-IR-172, page 5.

overtime is equivalent to about 15 full time positions working 2,080 hours each per year. By this metric, at least 15 of the 22 new operations positions could be justified simply with overtime savings. However, there has been no showing by HECO that its planned staffing changes or the total level of Production Operations labor hours (including continued high overtime levels) in the test year are reasonable, particularly in the context of an average test year with fully normalized overtime.

Q. HAS HECO ACCOUNTED FOR THE FACT THAT ADDING NEW OPERATORS AT THE HONOLULU AND WAIAU PLANTS SHOULD PRODUCE SIGNIFICANT OVERTIME SAVINGS IN THE TEST YEAR?

A. No. Inexplicably, the overtime hours for the Waiau operations are projected to actually <u>increase</u> by 705 hours over 2004 actual levels in the Company's rate case forecast, in spite of increased staffing levels to add nine employees throughout all months of the 2005 test year.[25] At the Honolulu power plant, a reduction of 4,570 hours of overtime is projected, but the reduction is not

[25] CA-IR-635, pages 7 & 8, show Waiau Operations RA=PIW overtime hours totaled 20,107 hours in 2002, 23,641 hours in 2003 and 22,760 hours in 2004, relative to Test Year projected overtime hours of 23,465. Thus increasing staffing by 9 positions (HECO-619) is predicted to yield no overtime savings.

sufficient to offset the increased staffing of nine additional employees being proposed.[26]

Q. ANOTHER PROBLEM YOU HAVE NOTED WITH RESPECT TO TEST YEAR PRODUCTION OPERATIONS LABOR EXPENSES IS THE COMPANY'S ASSUMPTION THAT EACH NEWLY CREATED POSITION HAS BEEN FILLED THROUGHOUT ALL 12 MONTHS OF THE TEST YEAR, WITH NO VACANCIES ASSUMED FOR ANY POSITIONS. PLEASE EXPLAIN THIS PROBLEM.

A. Actual HECO staffing levels in the early months of 2005 are much lower than the Company seeks to include in the revenue requirement, because the Company has included wage and benefit costs for all of the new employee positions starting at the very beginning of the test year. As of January 1, 2005, HECO had not filled many of the positions for which labor costs were included in the 2005 test year expense projections. In fact, many of the new positions had not been approved by senior management at the beginning of 2005.[27] However, HECO's 2005 test year forecast assumes that each position was authorized and filled throughout the entire test year. In addition, HECO also

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26 Id. Honolulu Operations RA=PIH overtime hours in 2002 were 6,646, in 2003 were 7,233 hours and in 2004 were 9,489 hours, compared to test year projected 4,919 hours of overtime. Thus increasing staffing by 9 positions (HECO-619) at Honolulu is predicted to yield overtime savings equivalent to only about 2 employees.

27 CA-IR-1, HECO T-6, Attachment 5 indicates for many positions, "Awaiting approval to fill."

assumed that no vacancies existed throughout the year.[28] Thus, the Company's labor forecast is inconsistent with the known facts of HECO's work force in early 2005, resulting in overstatement of labor costs.

Q. EARLIER IN YOUR TESTIMONY, YOU DESCRIBED THE IMPORTANT DISTINCTION BETWEEN AN AVERAGE AND A YEAR-END OR "ANNUALIZED" TEST YEAR. UNDER THE AVERAGE TEST YEAR CONCEPT USED TO MEASURE REVENUES, RATE BASE AND OTHER EXPENSE ELEMENTS OF THE REVENUE REQUIREMENT IN THIS DOCKET, HOW SHOULD LABOR-RELATED EXPENSES BE QUANTIFIED?

A. Labor related expenses should be quantified based upon test year <u>average</u> staffing levels, to maintain consistency with the average test year concept. To this end, the Consumer Advocate is proposing adjustments to the Company's forecasted labor expenses to reflect payroll costs based upon the average of the beginning of year (actual January 1, 2005) and forecasted end of year employee levels.

Q. IF LABOR EXPENSES ARE BASED UPON THE AVERAGE OF JANUARY 1 ACTUAL AND DECEMBER 31 PROJECTED STAFFING LEVELS, AS YOU PROPOSE, WILL THERE STILL BE A PROBLEM ASSOCIATED WITH

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28 See also HECO response to CA-IR-174, parts a and b.

IGNORING VACANCIES THAT MAY EXIST AT DECEMBER 31 2005 THAT ARE NOT REFLECTED IN THE PROJECTED EMPLOYEE LEVELS?

A. Yes. It is highly probable that HECO, like other utility companies and other large businesses, will never be able to maintain full employment across nearly 1,500 employee positions.[29] Continuous turnover in the workforce is a normal phenomena resulting from retirements, resignations, terminations for cause, disabilities and other causes. HECO's rate filing is unrealistic in its assumption that full staffing of each budgeted position will exist throughout every month of the test year.

By fully including HECO's projected staffing increases within the December 31 data point of the two-point average used to calculate labor costs, the Consumer Advocate has probably erred in the Company's favor and overstated average labor costs somewhat for the 2005 test year. On the other hand, it is conceivable that HECO may succeed in filling most of the proposed new positions and retaining existing employees within existing positions by year-end, particularly if required to do so under rate case scrutiny. If this occurs, the adjustment I propose will allow for a full complement of desired employee levels as of the end of the average test year.

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29 HECO-1612 indicates a budgeted total employee complement of 1,493 positions.

Q. HAS HECO ATTEMPTED TO EXPLAIN ITS FULL STAFFING ASSUMPTION USED IN ITS RATE FILING?

A. Yes. In its response to CA-IR-174, the Company describes certain new practices initiated in 2005 that are intended to "offset the vacancy gaps created in the past while creating sufficient overlap for knowledge transfer." The Company also argues in this response that any vacancy cost savings may not be significant when actual staffing levels are below full employment because, "Where vacancies exist, offsetting costs are incurred through higher levels of overtime and cost for outside services." However, these arguments are not consistent with HECO's actions and statements throughout the balance of its filing. If vacant positions actually had the effect of increasing overall costs as CA-IR-174 suggests, HECO would <u>not</u> have imposed hiring restrictions in the past to reduce costs as part of the "cost reduction programs" referred to by Mr. Alm.[30] As noted previously, HECO actually imposed an operating budget reduction in 2005 to recognize an "Even Hiring Lag" cost constraint – which would be illogical if HECO truly believed that vacant positions serve to increase over-all costs.

Q. HAS HECO REDUCED OVERTIME AND OUTSIDE SERVICES COSTS TO BE CONSISTENT WITH ITS ASSERTION THAT ELIMINATING HISTORICAL

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[30] CA-IR-12, part a.

STAFFING VACANCIES WILL CAUSE SAVINGS IN THESE "OFFSETTING COSTS"?

A. No. As noted previously, the Company's rate case forecast appears to overstate all costs, because projected staffing is increased and vacancies are presumed to not exist, yet projected overtime hours and costs for outside services have not declined relative to historical levels.[31] The Consumer Advocate is proposing adjustments to normalize test year projected labor costs so as to make the staffing projections consistent with the average 2005 test year used to quantify other elements of the revenue requirement and to normalize overtime levels.

Q. PLEASE EXPLAIN THE CALCULATIONS SUPPORTING THE PRODUCTION OPERATIONS LABOR COST ADJUSTMENT YOU SPONSOR.

A. I propose an adjustment to Production Department labor expenses, which is calculated in Workpaper CA-WP-101-C8,9 and then posted in two parts, at line one of CA Adjustment Schedule C-8 (Production Operations portion) and CA Adjustment Schedule C-9 (Production Maintenance portion). This adjustment restates projected test period employee headcounts to an average basis, using actual December 31, 2004 workforce statistics for the beginning of year average calculations.

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[31] CA-IR-635 indicates test year overtime hours above both 2003 and 2002 levels and only modestly lower than 2004 levels. Non-labor expenses are increased above all prior years except 2000, as shown in HECO-618 (Operations) and HECO-622 (Maintenance).

The starting point for the Consumer Advocate's adjustment to Production Operations labor expenses is the actual December 31, 2004 employee headcount data for each Production Department RA contained within the Company's forecast workpapers provided in the response to CA-IR-1, HECO T-6, Attachment 5. Since HECO has assumed all of its projected staffing, including existing and added new positions, were filled throughout the entire test year, the 2005 test year employment statistics in the Company's filing were used to quantify test year end (December 31, 2005) employment. The actual beginning-of-year and projected end-of-year headcounts are then averaged together with actual December 31, 2004 actual employment levels to determine the appropriate test year <u>average</u> number of employees, consistent with the average test year approach used throughout the balance of the rate case.

A percentage adjustment factor was then derived from the calculated average test year employee staffing levels, compared to HECO's forecasted test year staffing levels, to adjust HECO's proposed direct labor expense amounts for each RA proportionately to reflect an average test year projection. The Direct Labor by RA expense amounts were input from the response to CA-IR-1, HECO T-6, Attachment 3 and Attachment 4.

Q. WHY IS IT REASONABLE TO ACCEPT THIS AVERAGE TREATMENT OF HECO'S PROPOSED EXPANSION OF ITS PRODUCTION OPERATIONS WORKFORCE?

A. The average treatment of increasing workforce levels is appropriate for several reasons. First, the average approach is necessary to maintain consistency with the overall average test period concept being used to measure all other elements of revenues, expenses and rate base in this Docket. Second, some recognition of structural vacancies is appropriate because no employer is able to maintain full staffing for every authorized position in its organization throughout every day of the year. The average approach incorporates recognition of actual workforce levels at the beginning of the test year to recognize actual vacancies with 50 percent weighting of the earlier actual employee level data. Third, the end result of the adjustment resulting from averaging workforce levels is a production operations labor expense value that compares more reasonably with historical expenditure levels and with the operating budget HECO is actually using for internal management in 2005 that includes a full accounting for an "Even Hiring Lag."

Q. AFTER RESTATING STAFFING LEVELS AND RELATED LABOR COSTS TO AN AVERAGE OF JANUARY 2005 ACTUAL AND DECEMBER 2005 PROJECTED HEADCOUNTS, PLEASE DESCRIBE WHY YOU DID NOT

FIND IT NECESSARY TO SEPARATELY NORMALIZE OVERTIME HOURS AND LABOR EXPENSES FOR PRODUCTION OPERATIONS PERSONNEL?

A. Overtime labor hours and costs are included in the total direct labor expense amounts subjected to the Consumer Advocate's adjustment factor within the average staffing adjustment. Thus, some ratable downward adjustment to overtime labor costs is accomplished in this adjustment, in direct proportion to the headcount adjustment. The result is a modest downward adjustment to both straight time and overtime hours, proportionate with the average employee adjustment factors for each RA.

Q. IS THE ADJUSTMENT TO PRODUCTION OPERATIONS STAFFING THAT YOU SPONSOR SENSITIVE TO THE COMPANY'S NEED TO MEET GROWING DEMANDS ON ITS AVAILABLE CAPACITY?

A. Yes. In its response to CA-IR-173, HECO provided some excerpts from an "Oahu Electricity Situation" executive presentation given to the Commission and Consumer Advocate Staff regarding the anticipated generation shortfall due to rapid load growth and stated:

> Senior management approved the increase [in staffing] as part of a broader capacity shortfall mitigation plan. The impact to staffing levels include increased staffing to support increasing the availability of H8&9 and W3&4 to 24x7 coverage; developing and night shift maintenance organization to provide off-peak (night shift) maintenance capability on available baseload, cycling and peaking units; and increasing the number of specific trades and craft positions to handle a higher volume of maintenance required as a result of operating the units longer and harder. The specific positions are identified in CA-IR-48.

The Consumer Advocate's labor adjustment provides for a ramping of staffing levels for production operations personnel throughout the year 2005, so as to provide more resources to assure continued favorable availability of the Company's generating resources. This ramping effect simulates HECO's actual management of the Company's workforce, where positions are being gradually approved and filled during the year, in a manner consistent with the "Even Hiring Lag" operating budget targets. The Consumer Advocate's adjustment also provides for large amounts of overtime throughout 2005 in the Production Department RAs that are responsible for operating and maintaining HECO generation resources.

Q. ASIDE FROM THE LABOR COST PROJECTION ISSUES YOU HAVE DESCRIBED, ARE THERE ALSO PROBLEMS WITH HECO'S PROPOSED NON-LABOR PRODUCTION OPERATIONS EXPENSES?

A. Yes. CA Adjustment Schedule C-8 also sets forth a series of non-labor Production Operations expense items that HECO has included in its 2005 test year projections that should be revised or eliminated. These include:

- Normalization of city water costs for Kahe generating station, which are overstated in the Company's 2005 forecast.
- Normalization of the Hawaii Department of Health ("DOH") Emission fees to recognize the recent frequency of fee "waivers" recently granted by the DOH.

- Elimination of the Sun Power for Schools program expenditures that will be offset by contributions from participating customers.
- Elimination of the projected R&D costs for the Electronic Shock Absorber project for which no expenditures have occurred in 2005 to--date and for which HECO may ultimately receive royalty payments to offset incurred costs.
- Rescheduling of the remaining Kahe 7 costs that are being recovered over a five-year period through a $900,000 per year amortization that expires in September 2006.
- Overstated consulting fees for studies regarding purchasing power from tolling arrangements.

With these adjustments, non-labor projected 2005 test year Production Operations expenses are quantified at a level that is more representative of ongoing, recurring cost levels.

Q. PLEASE DESCRIBE THE KAHE CITY WATER PURCHASE COSTS THAT YOU ARE ADJUSTING.

A. Substantial amounts of city water are required for generating station use and the expense for purchases of such water must be estimated for the test year. In its rate case forecast, HECO has included $15,600, $22,800 and $285,732 to purchase water in the 2005 test year from the Honolulu Board of Water Supply ("BWS") for the Waiau, Honolulu, and Kahe power plants, respectively.[32] These amounts compare reasonably to the historical expense levels for the Waiau and Honolulu power plants, but are significantly larger than historical cost levels for Kahe.

According to HECO's response to CA-IR-462 at page 119, the actual costs recently incurred to purchase water from the BWS for Kahe have been about $163,000 per year. The Company's workpaper for this item displays an originally forecasted level of $180,000 per year, which would be an approximate 10 percent increase. However, instead of including this amount in the forecast, another $48,000 was penciled in and then another $57,732 was added with a pencil comment stating, "Revised budget amt not reflected on this sheet. Can't locate supporting doc to show change."[33] Thus, HECO's projected cost of water for Kahe amounted to $285,732 for the 2005 test year.

Based on the above CA-IR-664 was submitted seeking additional information about the higher level of projected cost to purchase water. In its response HECO admitted that the projected city water expense should be reduced from $285,732 to $185,280 for the Kahe station, a downward adjustment of approximately $101,000. The Consumer Advocate accepts this revision and has posted the required adjustment at line 5 of CA Adjustment Schedule C-8.

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32 CA-IR-2, HECO T-6, Attachment 3A, pages 25 (Waiau), 5 (Honolulu) and 7 (Kahe), respectively.

33 Id.

Q. WHAT ARE THE DEPARTMENT OF HEALTH EMISSION FEES AND WHY IS ADJUSTMENT OF THESE FEES REQUIRED?

A. The State Department of Health ("DOH") assesses emission fees under the legal authority of the Clean Air Act pursuant to Hawaii Revised Statutes ("HRS") Chapter 342B, and Hawaii Administrative Rules ("HAR") Chapter 11-60.1. The emission fee payments began in 1994 based upon HECO's 1993 emission levels.[34] Specific assessment factors are applied to actual emission rate data to calculate the amount that is payable to the DOH. However, with EPA's approval, the director of the DOH may waive annual fees due from owners or operators of covered emission sources for the following calendar year, provided that funds in excess of $6 million will exist in the Clean Air Special Fund-COV account as of the current calendar year.[35] It is this potential for difficult-to-predict emission fee "waivers" that complicates the determination of a ratemaking allowance for this expense element.

The history of HECO payments and fee waivers since implementation of the emission fee regulations was set forth in the responses to CA-IR-183 at page 2 and in CA-IR-643, as follows:

34 DOD/HECO-IR-5-1.

35 HAR 1-60.1-112(h).

Operating Year	Fees Payable	Amount Paid $000
1993	1994	$ 602
1994	1995	$ 624
1995	1996	$ 672
1996	1997	$ 677
1997	1998	$ 649
1998	1999	waived
1999	2000	$ 677
2000	2001	$ 671
2001	2002	waived
2002	2003	$ 748
2003	2004	waived
2004	2005	$ 842

HECO has interpreted this history and attempted to "normalize" for the periodic DOH fee waivers by applying a 70 percent factor to its estimated annual emission fees, based upon the presumption that historical waivers in three of the past ten years may indicate an ongoing waiver rate of 30 percent. However, this approach appears to understate the more recent pattern of waiver activity and not fully account for the basis of the waivers, when the DOH fund balances reach in excess of $6 million.

Q. HOW SHOULD HECO'S EMISSION FEE EXPENSE NORMALIZATION BE ADJUSTED TO RECOGNIZE THE PERIODIC WAIVERS THAT HAVE OCCURRED AND MAY OCCUR IN THE FUTURE?

A. It is notable that there were no emission fee waivers granted in the first five years of the history presented above, while in the more recent seven years there were waivers in three of the seven. The absence of waivers at the inception of the emission fee program may reflect that it would not have been possible for the DOH to accumulate sufficient funding to reach the $6 million threshold for fee waivers. It is the Consumer Advocate's recommendation that more recent experience be relied upon to estimate the fee waiver factor, rather than the ten-year period advocated by HECO. Substitution of the most recent five-year period suggests a waiver factor of 40 percent, since fees were waived in two of the past five years. The Company's response to CA-IR-643 indicates that total emission fees payable in 2005 were $842,000,[36] which the Consumer Advocate would multiply by 60 percent to reflect the impacts of the 40 percent average fee waiver history, as shown in CA Adjustment Schedule C-8, at lines 9 – 15.

Q. WHY HAVE YOU ELIMINATED THE SUN POWER FOR SCHOOLS PROGRAM COSTS, AS INDICATED AT LINE 16 OF CA ADJUSTMENT SCHEDULE C-8?

A. In its response to CA-IR-186, HECO explained various technology project expense estimates and stated:

> Since the amount of Sun Power for Schools non-labor expenses will be offset by the contributions by participating customers, the test year expense should be revised to reflect the offset. HECO will revise its test year estimates to reduce the Sun Power for Schools test year expense to zero in its rebuttal testimony.

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[36] CA-IR-643 states that Emission Fees payable to the DOH were $476,070 for Kahe, $313,649 for Waiau, and $51,826 for Honolulu Power Plants, totaling approximately $842,000 overall.

Q. HAS HECO INCLUDED OTHER INDIVIDUALLY SIGNIFICANT RESEARCH PROJECT COSTS IN THE TEST PERIOD FORECAST?

A. Yes. The Company has included a $100,000 "placeholder for the biomass initiative" and claims to have "plans to contract with the Southwest Research Institute to conduct emissions testing in a combustion turbine combustor rig fired with biofuel blends. HECO has a pending contract with Southwest Research Institute in the amount of $154,794. HECO plans to use a portion or all of the test year biomass initiative expense to co-fund this project (R&D funds from HECO's Electric Power Research Institute membership will supplement this project's funding). The biomass initiative funding may also be used for possible studies and activities related to co-firing of biomass." The Consumer Advocate is concerned with allowing such a "placeholder" for uncertain ongoing cost levels for biomass R&D, but is proposing no adjustment for this item.

On a much grander scale, HECO has included $500,000 for an R&D project it refers to as an Electronic Shock Absorber ("ESA"). According to comments within HECO's forecast workpaper documentation provided in response to CA-IR-2, HECO T-6, Attachment 3B at page 6, "Research & Development – Design and build an Electronic Shock Absorber device to test the minimization of power fluctuations between wind farms and the utility grid." According to the response to CA-IR-185, about $151,000 was spent on this project in 2004, but "No costs have been incurred to date in 2005."

Additionally, HECO has received a patent on the ESA technology and has signed an Intellectual Property Agreement that provides, "Per the Intellectual Property Agreement, HECO would be getting a royalty payment as a function of the sales of the ESA devices by S&C Electric." This response also explains that, "EPRI funds were not used in the development of the ESA because EPRI would have kept all intellectual property rights and any future revenues related to the device." Thus, HECO appears to anticipate a "payback" on its investment in ESA research and development.

Given these facts, the Consumer Advocate recommends that costs incurred prospectively for ESA development be deferred as a regulatory asset, net of any royalties or other income received, for consideration and possible rate recovery in future regulatory proceedings. This avoids putting ratepayers at risk for potential over-recovery of one-time project costs and ensures reconciliation of ESA costs and income prior to any rate recovery.

Q. IF THE COMMISSION DISAGREES WITH THE CONSUMER ADVOCATE'S PROPOSED DEFERRAL AND POSSIBLE FUTURE RECOVERY FOR THE ELECTRONIC SHOCK ABSORBER PROJECT, SHOULD SOME OTHER ADJUSTMENT BE MADE?

A. Yes. If the extraordinary $500,000 cost level for this program is not fully excluded from the test year, as I recommend, an alternative adjustment should be made to allow only $121,000 for HECO. This is the revised amount of payments HECO actually anticipates making in 2005, based upon its response to CA-IR-639, part d ($90,870 in September 2005 and $30,290 in December 2005).

Q. PLEASE EXPLAIN THE ADJUSTMENT YOU SPONSOR IN CA ADJUSTMENT SCHEDULE C-8 FOR KAHE 7 AMORTIZATION COSTS.

A. In Docket No. 95-0047 the Consumer Advocate and HECO reached agreement providing for the amortization over five years of $4.5 million of expenses incurred for Kahe Unit 7 project costs.[37] That amortization was commenced in October 2001 and will be completed in September 2006, only nine months after the end of the test year. The remaining unamortized balance for the Kahe 7 amortization as of 12/31/04 was $1,575,000 and at 12/31/05 is projected to be only $675,000,[38] yet HECO has included $900,000 in annual expenses in the test year for this amortization. This amount would be collected from customers in every future year that the electric rates determined in the instant proceeding remain in effect beyond the end of the 2005 test year.

To ensure that the specific amount of costs intended to be recovered pursuant to this Settlement is <u>not</u> exceeded, the adjustment set forth at

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37 The settlement was approved in Hawaii PUC Decision and Order No. 18872 issued September 5, 2001. Amortization costs are included in RA=PYA, see CA-IR-2, HECO T-6, Attachment 3D, page 4.

38 DOD/HECO-IR-6-12.

CA Adjustment Schedule C-8, lines 21-24 has the effect of rescheduling the remaining unamortized cost as of December 31, 2004, over a four year period during which rates established in this Docket are presumed to remain in effect. In the absence of such a "rescheduling," the Kahe 7 deferred costs would be over-recovered starting in October of 2006 at a rate of $75,000 per month until rates are adjusted in a "next" HECO general rate case.

Q. WHAT IS THE FINAL ADJUSTMENT FOR NON-LABOR PRODUCTION OPERATIONS EXPENSES, AS SET FORTH AT LINES 25 AND 26 OF SCHEDULE C-8?

A. HECO included projected expenses to hire a consultant to perform studies of purchase power tolling arrangements. In its response, to DOD/HECO IR 6-13, the Company stated its decision to not proceed with such studies and indicated that it will, "reduce Test Year 2005 Other Production, Non-Labor expense by $75,000 as part of its rebuttal testimony."

B. PRODUCTION MAINTENANCE EXPENSE

Q. WHAT ARE PRODUCTION MAINTENANCE EXPENSES AND HOW ARE THEY TREATED IN THE COMPANY'S FILING?

A. Production Maintenance expenses include the labor and non-labor costs incurred to repair and maintain generating units and related generating plant facilities. HECO has developed forecasts of 2005 test year Production

Maintenance expenses by evaluating costs anticipated to arise from scheduled generating unit overhauls, which are referred to as "project" costs, as well as ongoing non-overhaul maintenance activities and expenditures.

Q. WHAT AMOUNT OF PRODUCTION MAINTENANCE EXPENSE IS PROPOSED BY HECO IN ITS RATE FILING?

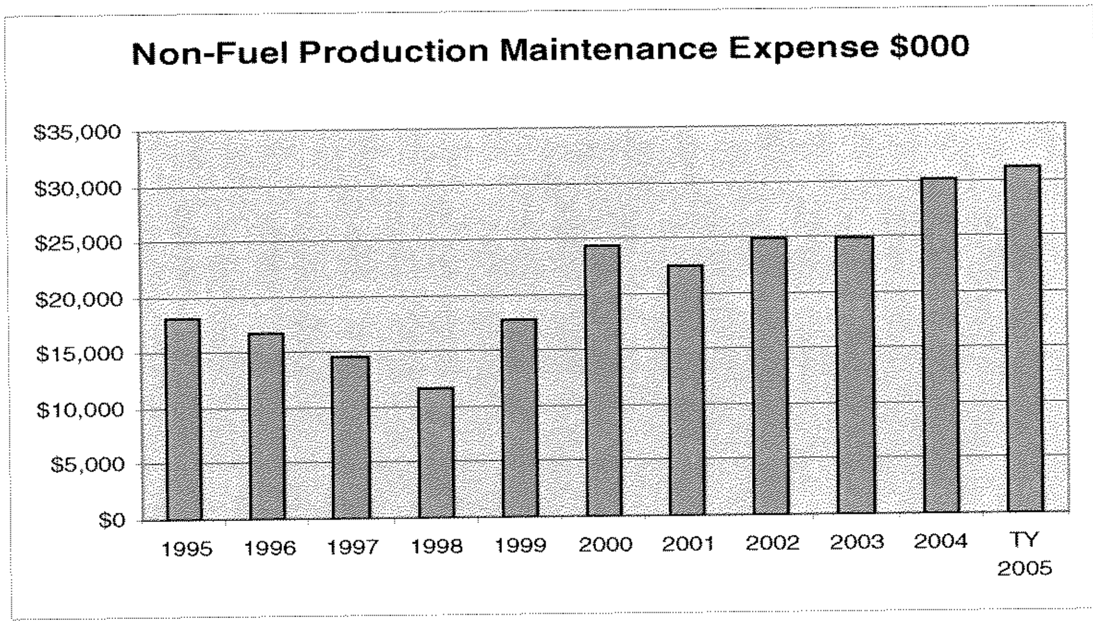
A. HECO-615 indicates that the Company's test year projected 2005 Production Maintenance expense totals $31,003,000 prior to ratemaking adjustments.[39] According to Mr. Fujinaka (HECO T-6) at page 27:

> The budget for Other Production Maintenance Expense is the summation of the labor and non-labor forecasts for work to be done by maintenance personnel at each of the three generating stations. In addition to the respective station maintenance personnel, there is a group of traveling maintenance personnel that jointly support project and overhaul work at the three generating stations.

Mr. Fujinaka's proposed Production Maintenance expense amount is a much higher level of Production Maintenance expense than HECO has actually incurred in prior years except for 2004, when extraordinary fourth quarter expenditures pushed the total 2004 expenses to an amount that is nearly

39 Ratemaking adjustments increase the forecasted value by $161,000. HECO's proposed ratemaking allowance for Production Maintenance expenses is $31,164,000.

equal to the test year proposed levels, as shown in the following graph:



Historical Production Maintenance expenses vary significantly from year-to-year and the test year levels is nearly triple the 1998 maintenance expenses of $11.7 million, which represents the low of the historical experience.

Q. WHAT FACTORS CONTRIBUTE TO THE VARIABILITY IN PRODUCTION MAINTENANCE EXPENSE LEVELS FROM YEAR-TO-YEAR?

A. Most of the variability in Production Maintenance expenses is driven by changes in the scope and scheduling of major overhauls on the Company's generating units each year. In addition, significant fluctuation can occur in non-project related maintenance performed on the common plant structures and work performed as preventive, predictive and corrective maintenance between planned overhauls at each generating station. In each of these categories, unit overhauls and other maintenance, there are indications that the test period proposed level of activity is unusual and not representative of ongoing normal cost levels. In the short run, certain maintenance activities are discretionary and can be deferred, such that it is possible that the large ramp-up in maintenance expenses just in time for the rate case is partially explained by HECO efforts to defer discretionary projects until increased costs can be used to increase rate levels.

Q. CAN YOU PROVIDE ANY SPECIFIC EXAMPLES OF DEFERRED MAINTENANCE WITHIN THE COMPANY'S RATE CASE FORECAST WORKPAPERS?

A. Yes. An $850,000 expense associated with the Kahe Station pond cleaning and lining work is indicative of a specific maintenance project expense that has been deferred into the test year. According to documentation provided in response to CA-IR-2, HECO T-6, Attachment 4A at pages 3 and 4, this project is to remove about 7000 cubic yards of silt from the Kahe waste water treatment Pond 1A and was initially planned in early 2001 for completion in December 2002 because "This pond needs to be cleaned before additional silt accumulates and interferes with the operation of the waste water treatment system." The response to CA-IR-188 at page 4 illustrates how the apparent deferral of this project contributes to nearly $1 million in expenses for maintenance RA=PIP "Planning" in the test year, even though this RA has actually incurred less than $25,000 in total structures maintenance expenses in the preceding years 1999 through 2004.[40]

In addition to the projected expenses associated with the Kahe Pond Cleaning, HECO proposed test year expenses for structural maintenance at the three power plants in the test year that exceeds the actual overall level of costs incurred for corrosion control, painting and general station maintenance in 1999, 2001, 2002, 2003 and 2004.[41] Examples of other large non-labor test year expenses included for structural maintenance that contribute to cost increases include the following discrete items:

- Kahe station structural painting (units 1-6) $200,000[42]
- Waiau Paint Corrosion control $400,000[43]
- Kahe basin structural repairs $150,000 [44]
- Kahe basin dredging $ 50,000 [45]

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40 CA-IR-188 summarizes total charges by activity at each generating station and provides total actual expense amounts for Maintenance of Structures (NARUC Account 511) in each year 1999 through 2004, as well as forecasted amounts in the test year. The test year projected expenses of $4 million greatly exceed comparable expenses in all of the prior years except year 2000.

41 CA-IR-188, page 4. Only in 2000 did HECO actually spend more than $4 million on Account 511 Maintenance of Structures, when large projects at Kahe and Waiau contributed to costs comparable to proposed test year levels.

42 CA-IR-2, HECO T-6, Attachment 3A, page 10.

43 Id, page 27.

44 Id. page 11

45 Id.

- Kahe cathodic protection $150,000 [46]
- Kahe general plant (trend) $360,000 [47]
- Kahe Fuel Tank 11 (deferred from 2004) $210,000 [48]

By listing these discrete test year budget elements, the Consumer Advocate is not implying that the work or proposed cost levels associated with these items are unreasonable. The Consumer Advocate's concern stems from the observation that a significant amount of discretion is involved in deciding when and what structural maintenance work gets done in any particular year.

Since the overall level of maintenance expense proposed by HECO for the 2005 test year is quite high relative to historical levels, it is important for the Commission to understand the risk that ratepayers may be burdened with excessive expense levels in each future year new rates are in effect, if the Company's proposed test year expenses are not truly representative of ongoing normalized costs. Stated differently, if HECO manages in the future to defer or avoid any of the projected maintenance expenses that are included in the test year forecast employed in setting rates, the cost "savings" accrue entirely to the benefit of shareholders in the form of increased earnings. HECO management faces a strong financial incentive to adopt pessimistic

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46 Id.

47 Id. page 13.

48 Id. page 14.

assumptions regarding the ongoing costs required to maintain production facilities, so as to minimize the risks of cost under-recovery while maximizing the potential to improve earnings by reducing future O&M costs after test year values have been established for ratemaking purposes.

Q. HOW DOES THE PLANNED OUTAGE SCHEDULE FOR HECO'S GENERATING UNITS IMPACT PRODUCTION MAINTENANCE EXPENSES?

A. Profoundly. For its prefiled test year expense projections, HECO relied upon a specific overhaul schedule dated January 12, 2004 that included assumptions about the specific units to be overhauled and the scope of work associated with each such overhaul. This overhaul schedule supported HECO's test year proposed level of O&M in the amount of $14.5 million associated with overhaul projects.

Since the rate case filing was prepared, HECO has revised its overhaul schedule and related O&M overhaul budget at least two times, as set forth in the response to CA-IR-500. In a revised overhaul schedule dated February 3, 2005, the O&M costs would increase by $2.6 million to $17.1 million. Upon further revision in an overhaul schedule dated April 8, 2005, O&M costs associated with the assumed outages and work scopes would produce even higher total expenses of $18.2 million. All of these amounts are estimates for the entire year, based upon assumptions regarding scheduling and a scope of work won't become known until work on particular outages is completed.

However, from this information, it is obvious that HECO's production maintenance activities and estimated expenses are quite unsettled and volatile at the moment.

Q. WHAT DID HECO DO TO ENSURE THAT THE JANUARY 12, 2004 PLANNED OUTAGE SCHEDULE USED TO ESTIMATE TEST YEAR EXPENSES WAS TRULY NORMAL AND REPRESENTATIVE OF ONGOING CONDITIONS?

A. This question was asked in CA-IR-43. The Company's response was detailed and extensive as to how the test year outages schedule was developed, but provides only a generalized initial statement as follows:

> The 2005 test year overhaul schedule shown at the bottom of HECO-627 was considered a 'normal' overhaul year based on meeting normal overhaul inspection and repair requirements, and the fact that actual numbers of outages normally exceed the planned outages (As explained in the response to CA-IR-43, the 2005 overhaul schedule was revised as of 2/3/05, and was undergoing further revisions.)

It is not apparent from any information provided by HECO that the January 12, 2004 overhaul schedule was "normal" and indicative of ongoing cost levels supported by any systematic analyses of long term overhaul scoping or cost trends. In fact, the response seems to suggest that no "normalized" ongoing cost level can be determined because HECO is continuously revising its overhaul planning.

Q. GIVEN THE UNCERTAINTIES SURROUNDING NORMAL, ONGOING OVERHAUL ACTIVITY LEVELS AND EXPENSES, HOW DID THE CONSUMER ADVOCATE APPROACH THE RATEMAKING CHALLENGE ASSOCIATED WITH DETERMINING A REASONABLE RATE CASE ALLOWANCE FOR PRODUCTION MAINTENANCE EXPENSES?

A. The Consumer Advocate determined the labor component of Production Maintenance expense by using the same analytic approach applied to determine the test year Production Operations expenses. Labor costs were normalized based upon the average number of maintenance employees expected to be on staff during the test year. This also normalized the test year overtime levels. These calculations are set forth in workpaper CA-WP-101-C- 8/9, with the results carried forward to CA Adjustment Schedule C-9 at line 1.

With regard to Non-labor expenses, the Consumer Advocate is accepting the Company's expense estimates and all expenses projected by HECO in connection with its overhaul schedule, with only limited adjustments to remove certain lowest priority discretionary maintenance projects that are fully funded within HECO's forecast. The details of this Non-Labor expense adjustment are described below and are set forth at lines 2 through 12 of CA Adjustment Schedule C-9.

Q. IN THE PREVIOUS SECTION OF YOUR TESTIMONY, YOU EXPLAINED HOW HECO HAD PROPOSED TO INCREASE PRODUCTION <u>OPERATIONS</u> EXPENSES FOR A SIGNIFICANTLY EXPANDED WORKFORCE, BUT HAD FAILED TO ACCOUNT FOR SUCH ADDED EMPLOYEES IN A MANNER CONSISTENT WITH THE AVERAGE TEST YEAR AND IN A MANNER THAT RECOGNIZED THAT SOME POSITIONS WILL EXPERIENCE VACANCIES. DOES THAT SAME STAFFING ISSUE EXIST WITH RESPECT TO HECO'S PROPOSED PRODUCTION <u>MAINTENANCE</u> LABOR EXPENSES?

A. Yes. HECO-623 summarizes the 34 percent increase in Production Maintenance staffing that is proposed, by adding 40 new positions to the 118 existing Production Maintenance staffing level that existed at year-end 2003. For the test year, HECO has decided to expand maintenance staffing and explains this decision in its response to CA-IR-1, HECO T-6, page 3 as follows:

> Also, a permanent night shift maintenance crew for Waiau and Kahe stations is required to take advantage of off-peak periods to perform outage and other types of maintenance when the cycling and peaking units are off line, and base loaded units are operating at reduced loads. Maintenance overtime is also excessive as shown in (T-6, HECO 625). Other trades and craft positions and staff (Trainer and IT Specialist) are required to keep up with higher volumes of maintenance as the units continue to age, to manage the growing application of technology and develop the influx of new employees.

Furthermore, as in the case of the Production Operations staffing increases discussed earlier, what is not explained in this answer is why maintenance of the same fleet of generating units suddenly requires a 34 percent increase in staffing in the test year, given that such units have been "continuing to age" throughout recent history. Also unexplained is why no savings of the historically "excessive" historical overtime levels have been reflected in HECO's Production Maintenance expense forecast for 2005. Similarly, no savings in contract labor or outside services have been projected for test year Production Maintenance expenses, even though the 40 new employees should provide some ability to avoid hiring contractors that were required historically.

As in the case of Production Operations personnel, HECO has assumed that all 40 of the planned new maintenance positions were filled throughout all 12 months of the test year, even though actual staffing levels have not achieved budgeted levels. Therefore, the Consumer Advocate proposes that labor costs be adjusted to reflect the average number of Production Maintenance employees in the test year, using actual employment data at December 31, 2004 and assuming HECO reaches its proposed higher staffing levels by the end of the test year.

Q. DOES THE CONSUMER ADVOCATE'S PRODUCTION MAINTENANCE LABOR ADJUSTMENT ACCEPT HECO'S PLAN TO EXPAND ITS MAINTENANCE WORK FORCE BY YEAR-END 2005?

A. Yes. The Consumer Advocate has accepted HECO's assertion that it will fill all of the 62 additional Production Operations and Maintenance positions[49] it has requested by year-end 2005. However, by requiring consistency with the average test year concept, some recognition is given by the Consumer Advocate to the delays in actual hiring being experienced under the Company's "Even Hiring Lag", as well as the potential for ongoing vacancies within the ranks of Production Maintenance staffing in the future. As noted earlier, HECO has improperly assumed no vacancies across the entire workforce and has improperly annualized year-end projected staffing at proposed full employment levels as if all new employees were on the payroll throughout the test year.

Q. WHY HAS THE CONSUMER ADVOCATE ACCEPTED HECO'S REQUESTED STAFFING INCREASES IN THE PRODUCTION DEPARTMENT?

A. HECO claims to now be committed to hiring and maintaining much higher Production Department staffing in the future than has ever been required in the past, in an effort to provide safe and reliable service to customers while

[49] 22 for production operations and 40 for production maintenance.

meeting continued growth in sales.[50] The Consumer Advocate is supportive of this objective, but is concerned with the lack of any quantitative analysis of optimal staffing levels, work requirements or any measurable backlog of work requirements provided by HECO in support of staffing at the higher proposed levels.[51] HECO's testimony and responses to the Consumer Advocate's information requests refer only generally to increasing work requirements driven by increased generating unit operating hours, the age of generating units, growing demand levels and the complexity of scheduling outages.[52] In spite of this concern, considering the information put forth by Mr. Fujinaka and in responses to information requests, HECO's Production Maintenance staffing proposals are accepted in the Consumer Advocate's filing, as of December 31, 2005.

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50 In the broader context, HECO-1612 indicates that 39 of 110 additional positions are in the Production Department, with significant increases also proposed in Energy Delivery Construction and Maintenance, Energy Services and Customer Service departments.

51 See, for example, CA-IR-48, "The Company did not conduct any formal studies of the optimal staffing plan...", CA-IR-122, CA-IR-177, CA-IR-174, CA-IR-175, CA-IR-176, CA-IR-636 and CA-IR-495(c), "With regard to supplementing the workforce, there are no studies or analysis performed to determine the impact of increasing staff on reducing the need for outside services to supplement the workforce."

52 Id. See also HECO T-6, pages 23, 30, 33 and 34 and the response to CA-IR-644.

Q. SHOULD THE COMMISSION CONDITION ITS APPROVAL OF HECO'S INCREASED STAFFING UPON ANY FUTURE REPORTING REQUIREMENTS?

A. Yes. As a condition of such acceptance, the Consumer Advocate recommends that HECO be required by the Commission in its Decision and Order to provide a full and detailed accounting in its next rate case filing indicating its actual employment levels achieved as of December 31, 2005 and in each subsequent calendar quarter, in the format of Exhibit HECO-1612. This reporting would facilitate a review of HECO's commitment to the higher staffing levels it has asked to be included in the revenue requirement at this time. The Company should be willing to provide this information as proof that its rate case staffing levels are not overstated relative to actual operating practices.

If HECO actually staffs-up to the indicated levels by December 31, 2005 and maintains such staffing into the future, the Commission should also be able to evaluate actual operating experience at such higher staff levels in the next rate case to see the extent to which overtime hours and Non-labor expenses have been displaced or otherwise impacted by the increased staffing. As noted earlier in this testimony, there is no indication that HECO has studied or quantified any direct correlation between the proposed large increases in staffing levels and proposed high levels of test year overtime and contractor services within the Production Department.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO HECO'S PROJECTED NON-LABOR PRODUCTION MAINTENANCE EXPENSES THAT ARE PROPOSED BY THE CONSUMER ADVOCATE.

A. The Company's test year forecast includes Production Maintenance Non-labor expenses associated with planned outages for generating unit overhaul projects as well as various non-overhaul-related maintenance activities. Mr. Fujinaka testifies at page 13 that "The 2005 test year overhaul schedule shown at the bottom of HECO-627 represents a normal overhaul year" and the Consumer Advocate has accepted this representation and the associated expense levels.[53]

Excluding overhaul costs, one category of other Production Maintenance Non-labor expenses projected by HECO for 2005 clearly exceeds normal levels and is the subject of a Consumer Advocate adjustment. Maintenance of Structures expenses in NARUC Accounts 511 and 552 include costs incurred to maintain power plant facilities such as buildings and other

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53 In its response to CA-IR-44, HECO elaborated upon why this particular overhaul schedule is "normal". In CA-IR-645, HECO was referred to two later iterations of overhaul schedules that now exist for 2005 and asked to "Identify which of the three alternative test year production maintenance expense amounts ($14.5 million, $17.1 million, or $18.2 million) for overhauls is the most indicative of normal ongoing conditions." In its response, HECO simply stated, "Please refer to the response to CA-IR-499." In response to CA-IR-499, HECO asserted that "it would not be appropriate to classify one schedule as 'normal,' with the implication that other [outage] schedules are then deemed to be 'abnormal.' In this response the Company states, "HECO does not plan to change test year estimates, except to reflect the changes indicated in the may 5, 2005 revenue requirement update" but then continues to state,"...if revisions to individual expense items are proposed by other parties based on actual 2005 conditions (for example, some vacancies are still in the process of being filled as was indicated in response to CA-IR-48), HECO may propose revisions to other items (such as overhaul expenses) based on actual 2005 conditions (see response to CA-IR-43).

structures, land improvements, fuel storage equipment, paving, fencing, sewer systems and other facilities associated with the power plant site. For the test year, HECO has estimated $4,023,768 to these accounts, a level much higher than recent historical actual expense levels.[54] This account includes expenditures that are required to be performed, but are discretionary in the near term, such as structural painting, building repairs, basin dredging and concrete repairs. In response to CA-IR-244, HECO provided a prioritized listing of its "2005 Production O&M Priority List" that was fully funded with test year projected expenditures.[55] Upon review of this list, the Consumer Advocate proposes the removal of the seven lowest priority discretionary expenditures, so as to mitigate the impacts of the excessive overall expense levels being proposed by HECO for the test year Maintenance of Structures expense accounts.

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54 CA-IR-188, at page 4, compares this projected 2005 expense amount to actual values in 1999 through 2004.

55 DOD-HECO-IR-6-17 states, "Yes, the items on the "Production O&M Priority List" are included in the 2005 TY Other Production O&M Non-Labor expenses. The list is only a portion of the total 2005 TY Other Production O&M Non-Labor forecast."

Q. IS THE CONSUMER ADVOCATE'S PROPOSED EXCLUSION OF COSTS FOR THESE SEVEN PROJECTS BASED UPON A JUDGEMENT THAT HECO SHOULD NOT CONDUCT THE SPECIFIC WORK BEING REMOVED?

A. No. The Prioritized List was used to identify an amount of Maintenance of Structures that HECO has determined to be lowest priority, such that deferral of such discretionary work would not compromise safety, reliability or compliance with regulations. If any of these specific projects become more urgent, HECO can certainly elect to defer other discretionary projects and shift funding as necessary. The objective in making this adjustment is not to micro-manage HECO's production maintenance activities, but instead to include only a reasonable level of overall expense within the test year for ratemaking purposes.

Q. AFTER POSTING THIS ADJUSTMENT, HOW DOES THE REVISED MAINTENANCE OF STRUCTURES EXPENSE COMPARE WITH PREVIOUS YEAR'S ACTUAL EXPENDITURE LEVELS?

A. Upon removal of $690,000 for the lowest priority discretionary projects, test year Maintenance of Structures expense is reduced to $3.3 million. This amount is still larger than the expense HECO has actually incurred to maintain power plant structures in five out of the last six calendar years. Actual

Maintenance of Structures expenses were only $3.1 million in 2004, $1.5 million in 2003 and $2.2 million in 2002.[56]

Q. AT CA ACCOUNTING SCHEDULE C-11, A SEPARATE ADJUSTMENT IS MADE AT LINE 13 FOR THE ADOPTION OF BETTERMENT ACCOUNTING. PLEASE EXPLAIN THIS ADJUSTMENT.

A. This Consumer Advocate Adjustment reflects the expense impact of revising HECO's "betterment" accounting practice. Utilities generally follow mass asset accounting procedures that provide for capitalization of plant replacement parts only when a complete "unit" of property is replaced, at which time the existing property unit is retired from the plant records and the actual cost of the replacement property is capitalized. In contrast, when replacement parts are not individually large enough to be classified as a property "unit," they must be charged to expense when replaced. Betterment accounting is an exception to this accounting methodology that permits the capitalization of certain types of expenditures for minor plant asset replacements that are less than a "unit" of property and would normally be charged to expense. Under the applicable NARUC accounting rule, this exception applies when such a replacement asset "effects a substantial betterment (the primary aim of which is to make the property affected more useful, more efficient, of greater durability, or of

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56 CA-IR-188, page 4. The highest recorded expense in the past six actual years was in 2000, when expenses totaled $4.3 million.

greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate utility plant account."[57]

Prior to 2004, HECO had deviated from this NARUC accounting rule, by not limiting its capitalization amounts under betterment accounting to the "excess cost" defined above. In the settlement of a dispute regarding HECO's betterment accounting practices in Docket No. 03-0206, HECO agreed to modify its betterment accounting practice starting in 2004, to fully conform to the NARUC accounting instruction practice.[58] In Docket No. 03-0206, the Commission issued Decision and Order No. 21738 approving an Agreement between the Consumer Advocate and HECO that provided for a revision in HECO's utilization of betterment accounting. In its responses to CA-IR-416 (Revised 4-28-05) and CA-IR-641, the Company provided estimates of revisions to three construction projects for which projected incurred costs would be shifted from capital to expense accounts pursuant to the betterment accounting Agreement. The Adjustment being made by the Consumer Advocate at Schedule C-11 adopts HECO's estimate of the impact of the accounting method change, as provided in response to CA-IR-641, resulting in an increase to expense of $490,000.

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57 NARUC Uniform System of Accounts for Class A and B Electric Utilities, Utility Plant Instructions at 10.C.(3).

58 See CA-IR-416 and CA-IR-641.

X. DEPRECIATION AND AMORTIZATION

Q. PLEASE EXPLAIN THE ADJUSTMENT SET FORTH AT CA ADJUSTMENT SCHEDULE C-10.

A. This adjustment sets forth a revision to the Company's proposed annual depreciation expense, based upon updated actual depreciable Plant in Service balances as of December 31, 2004 and application of recently approved new depreciation accrual rates in Depreciation Docket No. 02-0391. Calculations supporting this adjustment are set forth in HECO's responses to CA-IR-86, as revised by CA-IR-514.

Q. WHAT IS THE REASON FOR THE ADJUSTMENTS TO AMORTIZATION EXPENSE THAT APPEAR AT CA SCHEDULE C-11?

A. HECO reduces its annual depreciation expense to recognize an amortization of capital that is contributed by its customers in the form of Contributions in Aid of Construction or "CIAC". This reduction appears at line 3 of HECO-1608. A small revision to this amount is required to recognize updated 2005 amortization of CIAC based on 2004 actual receipts, transfers and other transactions affecting the amortizable balance, as set forth in HECO's response to CA-IR-515.

HECO also charges to amortization expense amounts associated with Statement of Financial Accounting Standards No. 109 ("SFAS 109") accounting for income taxes, as described at page 13 of Mr. Okada's testimony (HECO T-17). A small adjustment to update this amortization is included at lines 4 through 6 of CA Adjustment Schedule C-11.

XI. NET PLANT IN SERVICE

Q. HOW DID THE COMPANY QUANTIFY ITS PROPOSED TEST PERIOD PLANT IN SERVICE AND DEPRECIATION RESERVE AMOUNTS, TO DERIVE NET PLANT IN SERVICE FOR RATE BASE?

A. The amounts reflected on HECO 1902 represent estimates of the Company's Original Cost Gross Plant in Service, Accumulated Depreciation and Removal Liability balances as of December 31, 2004 and at December 31, 2005.[59] These amounts are then averaged, using a simple two-point averaging calculation, to derive the "Net Cost of Plant in Service" balance included in the test year rate base.

Q. ARE THERE ADJUSTMENTS REQUIRED TO UPDATE THE COMPANY'S ESTIMATES USING MORE CURRENT AVAILABLE INFORMATION?

A. Yes. Several estimated values are updated in CA Adjustment Schedule B-1. First, the Company's estimated December 31, 2004 balances (which serve as the beginning point for computing the test year average balance) was updated to reflect the actual values provided by HECO in response to CA-IR-96. The

[59] The December 31, 2005 projections reflect the estimated additions for the 2005 test year. As will be discussed later in my testimony, some of the rate base elements, the Company has assumed no change in the December 31, 2004 balance will occur and has thus reflected this balance at December 31, 2005.

actual December 31, 2004 amounts are set forth in column C of CA Schedule B-1.

Similarly, in column D of this Schedule, each individual element of significance used by HECO to estimate the December 31, 2005 Net Plant in Service balances are updated and revised. The largest element for which a change is proposed is the projected Plant in Service net additions anticipated to occur during 2005. HECO has revised these projections in its update letter to the DOD and Consumer Advocate dated June 15, 2005, effectively removing about $29 million from the estimated plant additions for 2005. A factor, based upon the magnitude of the downward adjustment HECO has made for gross Plant additions, is derived by the Consumer Advocate at line 6 to make a corresponding downward adjustment to the estimate plant removal costs and salvage values, at lines 7 through 12. The Consumer Advocate's adjustments at lines 7 through 12 are necessary to reflect all adjustments associated with the change in estimated plant additions for the 2005 test year. The final element that is updated in Schedule B-1 is to reflect HECO's actual depreciation and amortization accruals as they will be booked throughout 2005, based upon the Company's response to CA-IR-86.

Q. ARE THE EFFECTS OF ADOPTION OF BETTERMENT ACCOUNTING, AS DESCRIBED IN YOUR PRIOR TESTIMONY, PROPERLY REFLECTED

WITHIN THE REVISED PLANT IN SERVICE ADDITIONS INCLUDED IN THE UPDATED RATE BASE?

A. Yes.[60]

XII. OTHER RATE BASE UPDATES.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT SCHEDULE B-2?

A. As previously stated, HECO's estimated average test year rate base represents the simple average of the estimated balances at December 31, 2004 and December 31, 2005. This Schedule summarizes several proposed adjustments to rate base elements other than net plant in service to reflect the actual December 31, 2004 data for purposes of determining the beginning test year balance (i.e., the balance at December 31, 2004) and in some instances to reflect revisions to December 2005 projected balances. The adjustments included in Schedule B-2 are limited to the rate base items for which substitution of actual recorded amounts at December 31, 2004 or updated December 2005 projected balances will significantly modify the average test year rate base amount. The following HECO rate base components were <u>not</u> included in this adjustment because the substitution of actual December 31, 2004 recorded balances in place of the Company's estimates would not significantly change the average test year rate base projection:

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60 The response to CA-IR-641 provides "As Revised" capitalized costs for three 2005 Projects that are reduced for Betterment Accounting revisions. These lower capital expenditure amounts are reflected in HECO's May 5, 2005 update letter at Attachment 6, page 2.

- Property Held for Future Use
- Unamortized OPEB Regulatory Asset
- Unamortized System Development Costs
- Unamortized ITC
- OPEB Liability

In addition, please note that fuel inventories and working cash are not part of the adjustment reflected on Schedule B-2 because these rate base elements are separately calculated by the Consumer Advocate using updated information other than the recorded December 31, 2004 balances (See Schedules B-8 and B-9).

Q. PLEASE EXPLAIN THE ADJUSTMENT APPEARING AT LINES 1 THROUGH 5 OF CA ADJUSTMENT SCHEDULE B-2.

A. Materials & Supplies inventories supportive of Production Department and T&D functions were updated using the December 31, 2004 actual inventory balances provided in response to CA-IR-95, page 3, in place of the Company's estimated balances.

Q. WHAT IS THE PURPOSE OF THE PREPAID PENSION ASSET ADJUSTMENT APPEARING AT LINES 8 THROUGH 12?

A. HECO has recorded on its balance sheet a cumulative difference between the pension expense and the funded pension, calling this difference a Prepaid

Pension Asset. While Mr. Carver (CA-T-2) discusses the proper ratemaking treatment of this difference in his testimony, CA Adjustment Schedule B-2 simply revises the balances to reflect HECO's updated December 31, 2004 recorded amounts, as well as revised estimates of the December 31, 2005 balance.

Q. WHAT IS BEING DONE TO UPDATE THE COMPANY'S CONTRIBUTIONS IN AID OF CONSTRUCTION RATE BASE OFFSET AT LINES 13 THROUGH 19?

A. Using the same procedure as employed to update Materials & Supplies inventories, the test year projected balances of Contributions in Aid of Construction have been adjusted to account for the actual recorded balance as of December 31, 2004.

Q. IS THE SAME APPROACH EMPLOYED THROUGHOUT THE BALANCE OF CA ACCOUNTING SCHEDULE B-2, SUBSTITUTING THE ACTUAL RECORDED DECEMBER 31, 2004 BALANCES IN PLACE OF HECO PROJECTED VALUES FOR THE BEGINNING OF YEAR AVERAGE CALCULATION OF OTHER RATE BASE ELEMENTS?

A. Yes. The Company's estimated December 2004 balances for Customer Advances, Customer Deposits, Accumulated Deferred Income Taxes, Unamortized SFAS 109 Regulatory Asset, and Unamortized Gain on Sales from line 20 through the end of CA Accounting Schedule B-2 are also revised to reflect the actual balances at December 2004 as well as certain changes to the projected balances as of December 31, 2005.

XIII. PROPERTY HELD FOR FUTURE USE.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO HECO'S PROPERTY HELD FOR FUTURE USE, AS SET FORTH IN CA ADJUSTMENT SCHEDULE B-5.

A. This adjustment removes from Property Held for Future Use ("PHFU"), the Company's investment in the Kalaeloa-Barbers Point Harbor pipeline that was installed in 1991 because the Company has no defined plan for use or commercial operation for the facility.

Q. WHAT HAS BEEN THE COMMISSION'S POLICY WITH RESPECT TO INCLUSION OF PHFU PROJECT COSTS IN RATE BASE?

A. The Company's response to DOD/HECO-IR-4-8 refers to D&O No. 11699 dated June 31, 1992 in which the Commission established a 10-year criteria to limit the exposure of ratepayers to pay for PHFU investments not having a near-term implementation plan. According to that response, "the 10-year criterion is meant to balance the risk of future higher acquisition cost or nonavailability of the property against the burden that ratepayers will need to bear by the inclusion of the property in PHFU for an extended period of time."

Q. HOW DOES HECO EXPLAIN ITS CONTINUED INCLUSION OF THIS PHFFU INVESTMENT WITHIN RATE BASE?

A. At HECO T-18, page 10, Ms. Nagata states, "Although it has been more than 10 years (i.e., installed in 1991) since the Kalaeloa-Barbers Point Harbor pipeline has been included in Property Held for Future Use and not yet placed in service for utility use, it is reasonable to continue to include its costs in Property held for Future use because of the unique circumstances under which the pipeline was constructed and installed."

While Ms. Nagata does not elaborate on the "unique circumstances" she references in response to CA-IR-206, HECO claims that it incurred costs for this project, "to preserve the option to use the Barbers Point Harbor for fuel operations, because not doing so when the pier was constructed may have precluded HECO from doing so in the future." The Company goes on to speculate that, "[f]uture use of HECO's facilities may depend on the inability to use the fuel suppliers' facilities, economic considerations, or other factors unknown at this time." However, in this response HECO concedes that, "[t]here are no updated studies addressing the probable date for the project nor has HECO identified any future date for placing the pipeline into service."

Q. IS IT REASONABLE TO BURDEN RATEPAYERS WITH THE COST OF THIS PLANT INVESTMENT INTO THE INDEFINITE FUTURE WHEN HECO HAS NO SPECIFIC PLAN TO EVER PLACE THE PIPELINE INTO SERVICE?

A. No. Unless HECO can demonstrate some specific implementation plan or other tangible ratepayer benefit from this PHFU investment, ratepayers should no longer be burdened with inclusion of the project cost within rate base. Ultimately, if and when HECO may one day find a use for the facility, the Commission could hear evidence regarding equitable treatment of carrying costs that may include recovery of a deferred return on investment for any periods when the asset was excluded from rate base.

The Consumer Advocate's recommendation is consistent with the Commission Decision and Order No. 11699 filed on June 20, 1992 in Docket No. 6998 wherein the Commission stated:

> More than ample time has expired since the acquisition of the properties for HECO to place them in service; and there is nothing to indicate that HECO's new projected service dates for these sites are any more reliable than HECO's old projections.
>
> The commission is mindful of the fact that this order may compel HECO to dispose of the sites and that HECO may later incur a greater cost to reacquire them or to acquire other sites. However, the 10-year criterion is mean to balance the risk of future higher acquisition cost or nonavailability of property against the bruden that ratepayers will need to bear by the inclusion of the property in PHFU for an extended period of time.

In its discussion, at footnote 29, the commission stated that:

> . . the commission acknowledged the prescription of period shorter than 10 years in other jurisdictions, but , in light of limited land space in this island state, deemed it reasonable for

Hawaii to allow the holding of property for future use for a longer period. We see no reason to change the 10-year criterion at this time.

XIV. <u>HECO UNDERGROUND COST-SHARING POLICY</u>.

Q. AT PAGE 16 OF HIS TESTIMONY, MR. ALM DISCUSSES HECO'S UNDERGROUND COST-SHARING POLICY AND NOTES THAT ADDITIONAL COSTS ARE INCLUDED WITHIN HECO'S TEST YEAR ESTIMATED PLANT IN SERVICE BALANCES AS A RESULT OF THIS POLICY. WHAT IS THE CONSUMER ADVOCATE'S POSITION REGARDING RATE RECOVERY OF ADDED COSTS ASSOCIATED WITH THE HECO UNDERGROUNDING POLICY?

A. The Consumer Advocate notes that HECO's asserted rate base includes approximately $2 million at year-end associated with additional costs incurred under the Underground Cost-Sharing policy that would not have been incurred under Tariff Rule 13 procedures. Because of the current magnitude of the costs and the fact that the costs have been incurred in good faith by HECO in an effort to resolve difficult issues of public policy, the Consumer Advocate does not oppose rate recovery of these amounts at this time. However, as such incremental facilities undergrounding costs continue to accumulate under the HECO policy in the future, consideration of capping such costs or refining the policy may be required to avoid excessive subsidization of certain customers receiving direct benefit from HECO's sharing policy at the "expense" of the general body of ratepayers.

Furthermore, the Consumer Advocate is presently in discussions with HECO to develop criteria that will allow for a means by which parties can independently review the application of the criteria and better assess the reasonableness of the costs associated with the implementation of the new policy for future rate proceedings.

XV. <u>FUEL INVENTORY</u>.

Q. WHAT IS PROPOSED BY THE COMPANY WITH RESPECT TO FUEL INVENTORIES INCLUDED IN RATE BASE?

A. The Company has included an allowance for fuel oil inventory balances within its asserted rate base, based upon a study of required inventory quantities that is sponsored by witness HECO-T-4, Mr. Sakuda. At HECO-408, the results of the fuel inventory study are summarized to yield a rate base allowance of approximately $28.7 million.

Q. DOES THE CONSUMER ADVOCATE PROPOSE ANY MODIFICATIONS TO THE COMPANY'S PROPOSED FUEL INVENTORY ALLOWANCE?

A. Yes. As more fully described by Mr. Herz (CA-T-3), the Consumer Advocate has calculated an updated fuel inventory balance consistent with its calculations underlying test year fuel expense.

Q. HOW WERE THE UNIT PRICES OF FUEL OIL DETERMINED FOR PURPOSES OF THE FUEL INVENTORY ALLOWANCE IN RATE BASE?

A. Latest known delivered fuel oil prices as of May 1, 2005 were employed. This approach has been used in prior rate cases and is consistent with the fuel unit prices employed in determining fuel expense.

Q. WHAT IS THE PURPOSE OF CA SCHEDULE B-8, THE ADJUSTMENT TO TEST PERIOD FUEL INVENTORY BALANCES?

A. This schedule incorporates the fuel inventory allowance that should be included in HECO's rate base, using the value recommended by Mr. Herz at CA-308, based upon the simulated dispatch load levels included in the Consumer Advocate's filing, and the May 1, 2005 unit prices for fuel as described above. The total inventory allowance, including an additive amount for the new Distributed Generation units at HECO substations, is compared to the Company's prefiled fuel inventory request to derive the adjustment required to increase fuel inventory to the Consumer Advocate's proposed level.

XVI. WORKING CASH.

Q. DID THE COMPANY PREPARE A WORKING CASH LEAD LAG STUDY AS PART OF ITS FILING?

A. Yes. Ms. Ohashi (T-19) sponsors a study of working cash based upon lead lag cash flow analyses. The lag day values for collection of revenues and for the payment of various cash expense items are summarized in Exhibit HECO-1907, which calculates the amount of working cash that HECO proposes to include in rate base based upon the timing of cash flows associated with the Company's operations. The specific lag day values are calculated within HECO-WP-1907, except for the revenue collection lag, which is calculated and sponsored by HECO witness T-9, Ms. Ejercito.

Q. HAS THE CONSUMER ADVOCATE PREPARED A COMPARABLE CALCULATION OF WORKING CASH WITHIN THE CA ACCOUNTING SCHEDULES?

A. Yes. Schedule B-9 sets forth a revised calculation of working cash, using the Consumer Advocate's recommended lag day values, applied to the Consumer Advocate's adjusted income statement projections for the test year. The Working Cash rate base allowance recommended by the Consumer Advocate is different from HECO's Working Cash recommendation because of differences in certain lag day values, and also because of differences in the adjusted income statement amounts to which the lag day values are applied.

Q. TO WHAT EXTENT DOES THE CONSUMER ADVOCATE AGREE WITH THE COMPANY'S LEAD LAG STUDY RESULTS?

A. There is agreement with respect to the general format and approach to the study and with some of the lag day values. Modifications are required, however, to restate and correct several of the Company's proposed lag day values. The changes I recommend are to:

- Revise HECO's revenue lag to recognize the improvement in revenue collection timing that has been experienced in recent years.
- Correct HECO's fuel expense lag days to reflect payment terms within the Company's new fuel oil supply contracts, and
- Revise HECO's O&M Labor lag days to recognize the more rapid deposits of withheld State Income Taxes, as now required under revised regulations.
- Revise HECO's O&M Non-labor lag days to eliminate the distortion caused by HECO's application of an assumed "zero" lag day value for accrual-based pension and Other Post Employment Benefit ("OPEB") expenses.

In addition to these substantive changes in the calculated lag days, application of the revised lag day values to the Consumer Advocate's adjusted operating expense levels produces a different rate base allowance for working cash, as shown on CA Schedule B-9.

Q. HAS THE CONSUMER ADVOCATE CALCULATED WORKING CASH AT PROPOSED RATE AND REVENUE LEVELS, TO COINCIDE WITH THE COMPANY'S CALCULATIONS AT PROPOSED RATES?

A. Schedule B-9 displays Working Cash calculated at both present rate levels and at the Consumer Advocate's proposed rate levels.

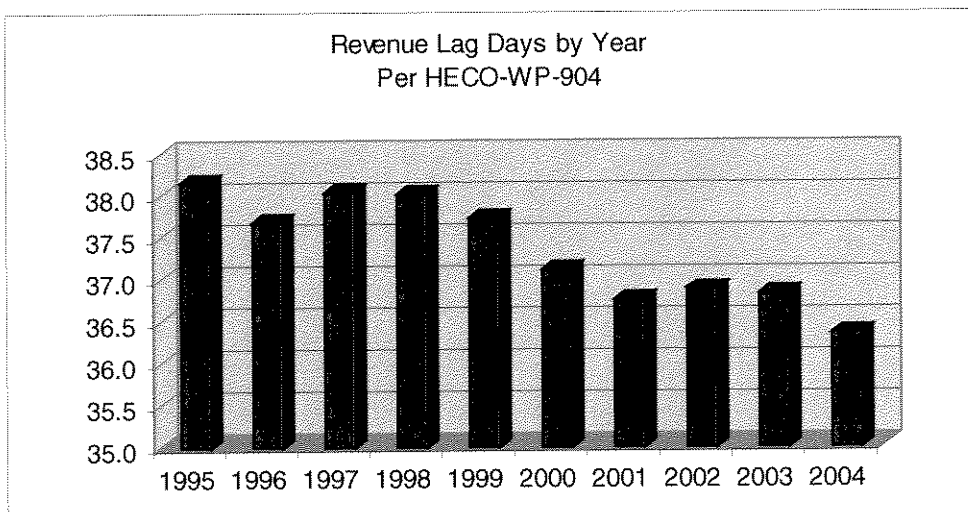
Q. PLEASE EXPLAIN YOUR FIRST LAG DAY ADJUSTMENT TO THE REVENUE LAG.

A. The "revenue lag" represents the number of days, on average, between the provision of electric services to customers and the receipt of cash revenues for such service. Thus, a larger (longer) revenue lag means that investors must "finance" more working capital while the Company is waiting for its customers to pay for service. A larger revenue lag therefore results in a larger rate base allowance for Working Cash.

The Company has proposed an estimated 38 day revenue collection lag for the 2005 test year. This estimated value is said to be reasonable by Ms. Ejercito (HECO T-9) at page 23 of her testimony:

> Over the past nine years from 1995 to 2003, the average revenue lag days was 37.5 days as shown on HECO-WP-904. The proposed 38 revenue lag days for the 2005 test year is consistent with HECO's historical experience and consistent with the 38 day revenue lag days approved by the Commission in HECO's previous test year 1995 rate case, Docket No. 7766, Decision and Order No. 14412, filed on December 11, 1995.

The referenced HECO-WP-204 contains calculations of annual revenue lag day values for each of the years 1995. Ms. Ejercito has interpreted this data by developing a nine-year average of 37.5 days that is said to be "consistent" with HECO's proposed use of a 38 day revenue lag. What is notable about this historical revenue collection data, however, is that HECO's actual revenue collection experience has been improving and a more reasonable value based upon the most recent information is 37, rather than 38 days. I have converted Ms. Ejercito's annual revenue lag values into a graphical presentation to illustrate this point:



Based upon a review of this information, the Consumer Advocate recommends use of a 37 day revenue lag, which appears to be conservatively generous to HECO because the actual revenue lag experienced by the Company has not been as high as 37 days in the last four years. HECO's proposed use of a 38.0 revenue lag day value is clearly unreasonable in comparison to actual revenue lag experience since 1998.

Q. TURNING TO THE NEXT LAG DAY ISSUE, WHY IS IT NECESSARY TO REVISE THE FUEL EXPENSE PAYMENT LAG DAY VALUE?

A. In its response to CA-IR-524, HECO provided a revised and corrected fuel oil payment lag calculation reflective of more appropriate assumptions regarding contractual terms with Chevron and Tesoro for rendering and payment of fuel oil invoices. The Company's prefiled fuel expense payment lag days are revised from 12 to 16 days in the Consumer Advocate's Working Cash calculation to adopt this revision.

Q. PLEASE DESCRIBE THE REASON FOR YOUR CHANGE TO THE O&M LABOR LAG DAY VALUE.

A. The labor lag is actually comprised of several elements of labor cost, including actual net pay to employees, as well as several tax and benefit withholding items. This blend of cost elements is discussed at pages 19-21 of Ms. Ohashi's testimony. The State of Hawaii has advanced the payment due dates for remittance by employers of State Income Tax amounts withheld from employee payrolls. A recalculation of the O&M Labor lag days to recognize this change is set forth at DOD/HECO-IR-9-8, yielding a revised 11 lag day value to replace the 12 lag day value used in HECO's Working Cash study.

Q. WHAT IS THE FINAL ADJUSTMENT TO LAG DAY VALUES IN SCHEDULE B-9?

A. In its study to estimate the O&M Non-labor expense payment lag day value, HECO adopted a new procedure that segregated expenses for certain expense items, such as pension and OPEB expenses, from other cash voucher payments that were sampled and analyzed. Ms. Ohashi explains this treatment at page 24,

> Another change was in the significant O&M non-labor payments (pension expense, OPEB, emission fees, and EPRI dues) which were separately identified and not included in the sampling of O&M non-labor payments. Separately identifying large O&M non-labor payments helps to minimize the potential for distortion in the payment lag study that may result if these large payments are picked up in the general sampling.

While the Consumer Advocate does not object in general to stratification of the non-labor expenses to segregate individually significant items, the approach used by HECO actually creates a "distortion" in the calculated O&M Non-labor lag day calculation because Ms. Ohashi elected to apply a presumed "zero" lag day payment value for the segregated pension and OPEB expense amounts, instead of actually studying or measuring the timing of cash flows associated with pension and OPEB funding transactions. These calculations are set forth at HECO-WP-1907, page 28 of 45, where the overall "O&M Non-Labor Payment Lag" of 29 days is shown to be a weighted average of calculated lag days for each line except for the "Pension" and "OPEB" amounts, where the test year expense is simply assumed to have a "0" lag value.

Q. WHAT SHOULD BE DONE WITH THE LAG VALUE CALCULATION FOR PENSION AND OPEB EXPENSES?

A. As a matter of policy, the Commission has determined that non-cash expenses not requiring current period cash payments, such as accrual-basis depreciation and amortization expenses, return on investment (operating income) and deferred income tax expenses, should not be included in working cash studies. This policy is acknowledged in Ms. Ohashi's testimony at page 15. Applying this policy, and recognizing that pension and OPEB expenses are accrual-basis expenses similar to depreciation and amortization, one might reasonably argue that these costs also must be entirely eliminated from any lead lag study of cash flows. On the other hand, if HECO is required to make cash funding contributions to its pension fund or to OPEB funding vehicles, one instead might elect to study the timing of such cash flows to estimate lag day values.

The Consumer Advocate would not object to the conduct of such studies of pension and OPEB cash flows in the future. However, HECO has conducted no cash flow funding studies and has instead simply included pension and OPEB accrued expense amounts using an assumed "zero" assumed payment lag, which understates the resulting weighted O&M

Non-Labor lag day value. To remedy this problem, the Consumer Advocate has recalculated the O&M Non-Labor lag days using <u>zero dollars and a zero lag day value</u> for pensions and OPEBS, as shown in CA-WP-101-B9, page 3. This revision completely neutralizes any impact associated with the inclusion of pensions and OPEBs and thereby prevents any, "...potential for distortion in the payment lag study that may result if these large payments are picked up in the general sampling" that Ms. Ohashi was concerned about. The corrected and revised lag day value of 31 days is then carried forward into CA Adjustment Schedule B-9 at line 4 in column C, to quantify Working Cash for rate base inclusion.

VI. <u>CONCLUSION.</u>

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does. My additional Direct Testimony addressing cost of service and rate design issues is designated CA T-5.

EXHIBITS

OF

MICHAEL L. BROSCH

MICHAEL L. BROSCH

Summary of Qualifications

EMPLOYER:	Utilitech, Inc. Regulatory and Management Consultants
POSITION:	President
ADDRESS:	740 NW Blue Parkway, Suite 204 Lee's Summit, Missouri 64086

PRIOR EXPERIENCE:

1978-1982	Missouri Public Service Commission, Senior Accountant
1982-1983	Troupe, Kehoe, Whiteaker & Kent CPA's, Regulatory Consultant
1983-1985	Lubow, McKay, Stevens and Lewis, Project Manager
1985-Present	Utilitech, Principal and President

DEGREES:
University of Missouri – Kansas City
Bachelor – Business Administration (Accounting 1978) "with distinction"

OTHER QUALIFICATIONS:
Certified Public Accountant – Certification in Kansas and Missouri

Member	American Institute of Certified Public Accountants Missouri Society of Certified Public Accountants Kansas Society of Certified Public Accountants Beta Alpha Psi, professional accounting scholastic fraternity
Seminars	Iowa State Regulatory Conference 1981, 1985 Regulated Industries Symposium 1979, 1980 Michigan State Regulatory Conference 1981 United States Telephone Association Round Table 1984 NARUC/NASUCA Annual Meeting 1988, Speaker NARUC/NASUCA Annual Meeting 2000, Speaker
Instructor	INFOCAST Ratemaking Courses Arizona Staff Training Hawaii Staff Training

PRIOR TESTIMONIES: (See listings attached)

Utility	Jurisdiction	Agency	Docket/Case Number	Represented	Year	Addressed
Kansas City Power and Light Co.	Missouri	PSC	ER-81-42	Staff	1981	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-81-208	Staff	1981	Rate Base, Operating Income, Affiliated Interest
Northern Indiana Public Service	Indiana	PSC	36689	Consumers Counsel	1982	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	URC	37023	Consumers Counsel	1983	Rate Base, Operating Income, Cost Allocations
Mountain Bell Telephone	Arizona	ACC	9981-E1051-81-406	Staff	1982	Affiliated Interest
Sun City Water	Arizona	ACC	U-1656-81-332	Staff	1982	Rate Base, Operating Income
Sun City Sewer	Arizona	ACC	U-1656-81-331	Staff	1982	Rate Base, Operating Income
El Paso Water	Kansas	City Counsel	Unknown	Company	1982	Rate Base, Operating Income, Rate of Return
Ohio Power Company	Ohio	PUCO	83-98-EL-AIR	Consumer Counsel	1983	Operating Income, Rate Design, Cost Allocations
Dayton Power & Light Company	Ohio	PUCO	83-777-GA-AIR	Consumer Counsel	1983	Rate Base
Walnut Hill Telephone	Arkansas	PSC	83-010-U	Company	1983	Operating Income, Rate Base
Cleveland Electric Illum.	Ohio	PUCO	84-188-EL-AIR	Consumer Counsel	1984	Rate Base, Operating Income, Cost Allocations
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC	Consumer Counsel	1984	Fuel Clause
Cincinnati Gas & Electric	Ohio	PUCO	84-13-EL-EFC (Subfile A)	Consumer Counsel	1984	Fuel Clause
General Telephone - Ohio	Ohio	PUCO	84-1026-TP-AIR	Consumer Counsel	1984	Rate Base
Cincinnati Bell Telephone	Ohio	PUCO	84-1272-TP-AIR	Consumer Counsel	1985	Rate Base
Ohio Bell Telephone	Ohio	PUCO	84-1535-TP-AIR	Consumer Counsel	1985	Rate Base
United Telephone - Missouri	Missouri	PSC	TR-85-179	Staff	1985	Rate Base, Operating Income
Wisconsin Gas	Wisconsin	PSC	05-UI-18	Staff	1985	Diversification-Restructuring
United Telephone - Indiana	Indiana	URC	37927	Consumer Counsel	1986	Rate Base, Affiliated Interest
Indianapolis Power & Light	Indiana	URC	37837	Consumer Counsel	1986	Rate Base
Northern Indiana Public Service	Indiana	URC	37972	Consumer Counsel	1986	Plant Cancellation Costs
Northern Indiana Public Service	Indiana	URC	38045	Consumer Counsel	1986	Rate Base, Operating Income, Cost Allocations, Capital Costs
Arizona Public Service	Arizona	ACC	U-1435-85-367	Staff	1987	Rate Base, Operating Income, Cost Allocations
Kansas City, KS Board of Public Utilities	Kansas	BPU	87-1	Municipal Utility	1987	Operating Income, Capital Costs
Detroit Edison	Michigan	PSC	U-8683	Industrial Customers	1987	Income Taxes

Consumers Power	Michigan	PSC	U-8681	Industrial Customers	1987	Income Taxes
Consumers Power	Michigan	PSC	U-8680	Industrial Customers	1987	Income Taxes
Northern Indiana Public Service	Indiana	URC	38365	Consumer Counsel	1987	Rate Design
Indiana Gas	Indiana	URC	38080	Consumer Counsel	1987	Rate Base
Northern Indiana Public Service	Indiana	URC	38380	Consumers Counsel	1988	Rate Base, Operating Income, Rate Design, Capital Costs
Terre Haute Gas	Indiana	URC	38515	Consumers Counsel	1988	Rate Base, Operating Income, Capital Costs
United Telephone -Kansas	Kansas	KCC	162,044-U	Consumers Counsel	1989	Rate Base, Capital Costs, Affiliated Interest
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income, Affiliate Interest
All Kansas Electrics	Kansas	KCC	140,718-U	Consumers Counsel	1989	Generic Fuel Adjustment Hearing
Southwest Gas	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income, Affiliated Interest
American Telephone and Telegraph	Kansas	KCC	167,493-U	Consumers Counsel	1990	Price/Flexible Regulation, Competition, Revenue Requirements
Indiana Michigan Power	Indiana	URC	38728	Consumer Counsel	1989	Rate Base, Operating Income, Rate Design
People Gas, Light and Coke Company	Illinois	ICC	90-0007	Public Counsel	1990	Rate Base, Operating Income
United Telephone Company	Florida	PSC	891239-TL	Public Counsel	1990	Affiliated Interest
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1990	Rate Base, Operating Income (Testimony not admitted)
Arizona Public Service Company	Arizona	ACC	U-1345-90-007	Staff	1991	Rate Base, Operating Income
Indiana Bell Telephone Company	Indiana	URC	39017	Consumer Counsel	1991	Test Year, Discovery, Schedule
Southwestern Bell Telephone Company	Oklahoma	OCC	39321	Attorney General	1991	Remand Issues
UtiliCorp United/ Centel	Kansas	KCC	175,476-U	Consumer Counsel	1991	Merger/Acquisition
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
United Telephone - Florida	Florida	PSC	910980-TL	Public Counsel	1992	Affiliated Interest
Hawaii Electric Light Company	Hawaii	PUC	6999	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Maui Electric Company	Hawaii	PUC	7000	Consumer Advocate	1992	Rate Base, Operating Income, Budgets/Forecasts
Southern Bell Telephone Company	Florida	PSC	920260-TL	Public Counsel	1992	Affiliated Interest
US West Communications	Washington	WUTC	U-89-3245-P	Attorney General	1992	Alternative Regulation
UtiliCorp United/ MPS	Missouri	PSC	ER-93-37	Staff	1993	Affiliated Interest
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-1151, 1144, 1190	Attorney General	1993	Rate Base, Operating Income, Take or Pay, Rate Design
Public S2ervice Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Affiliated Interest

Illinois Bell Telephone	Illinois	ICC	92-0448 92-0239	Citizens Board	1993	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Hawaiian Electric Company, Inc.	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	URC	39584	Consumer Counselor	1994	Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Cost Allocations, Rate Design
PSI Energy, Inc.	Indiana	URC	39584-S2	Consumer Counselor	1994	Merger Costs and Cost Savings, Non-Traditional Ratemaking
Transok, Inc.	Oklahoma	OCC	PUD-1342	Staff	1994	Rate Base, Operating Income, Affiliated Interest, Allocations
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income, Cost of Service, Rate Design
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Operating Income, Affiliate Interest, Service Quality
PSI Energy, Inc.	Indiana	URC	40003	Consumer Counselor	1995	Rate Base, Operating Income
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-880000598	Attorney General	1995	Stand-by Tariff
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
Mid-American Energy Company	Iowa	ICC	APP-96-1	Consumer Advocate	1996	Non-Traditional Ratemaking
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking
Southwest Gas Corporation	Arizona	ACC	U-1551-96-596	Staff	1997	Operating Income, Affiliated Interest, Gas Supply
Utilicorp United - Missouri Public Service Division	Missouri	PSC	EO-97-144	Staff	1997	Operating Income
US West Communications	Utah	PSC	97-049-08	Consumer Advocate	1997	Rate Base, Operating Income, Affiliate Interest, Cost Allocations
US West Communications	Washington	WUTC	UT-970766	Attorney General	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR 98-140	Public Counsel	1998	Affiliated Interest
ONEOK	Oklahoma	OCC	PUD980000177	Attorney General	1998	Gas Restructuring, rate Design, Unbundling
Nevada Power/Sierra Pacific Power Merger	Nevada	PSC	98-7023	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
PacifiCorp / Utah Power	Utah	PSC	97-035-1	Consumer Advocate	1998	Affiliated Interest
MidAmerican Energy / CalEnergy Merger	Iowa	PUB	SPU-98-8	Consumer Advocate	1998	Merger Savings, Rate Plan and Accounting
American Electric Power / Central and South West Merger	Oklahoma	OCC	980000444	Attorney General	1998	Merger Savings, Rate Plan and Accounting

ONEOK Gas Transportation	Oklahoma	OCC	970000088	Attorney General	1998	Cost of Service, Rate Design, Special Contract
U S West Communications	Washington	WUTC	UT-98048	Attorney General	1999	Directory Imputation and Business Valuation
U S West / Qwest Merger	Iowa	PUB	SPU 99-27	Consumer Advocate	1999	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Washington	WUTC	UT-991358	Attorney General	2000	Merger Impacts, Service Quality and Accounting
U S West / Qwest Merger	Utah	PSC	99-049-41	Consumer Advocate	2000	Merger Impacts, Service Quality and Accounting
PacifiCorp / Utah Power	Utah	PSC	99-035-10	Consumer Advocate	2000	Affiliated Interest
Oklahoma Natural Gas, ONEOK Gas Transportation	Oklahoma	OCC	980000683, 980000570, 990000166	Attorney General	2000	Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract
U S West Communications	New Mexico	PRC	3008	Staff	2000	Operating Income, Directory Imputation
U S West Communications	Arizona	ACC	T-0105B-99-0105	Staff	2000	Operating Income, Rate Base, Directory Imputation
Northern Indiana Public Service Company	Indiana	IURC	41746	Consumer Counsel	2001	Operating Income, Rate Base, Affiliate Transactions
Nevada Power Company	Nevada	PUCN	01-10001	Attorney General-BCP	2001	Operating Income, Rate Base, Merger Costs, Affiliates
Sierra Pacific Power Company	Nevada	PUCN	01-11030	Attorney General-BCP	2002	Operating Income, Rate Base, Merger Costs, Affiliates
The Gas Company, Division of Citizens Communications	Hawaii	PUC	00-0309	Consumer Advocate	2001	Operating Income, Rate Base, Cost of Service, Rate Design
SBC Pacific Bell	California	PUC	I.01-09-002 R.01-09-001	Office of Ratepayer Advocate	2002	Depreciation, Income Taxes and Affiliates
Qwest Communications – Dex Sale	Utah	PSC	02-049-76 02-049-82 01-2383-01	Consumer Advocate	2003	Directory Publishing
Qwest Communications – Dex Sale	Washington	WUTC	UT-021120	Attorney General	2003	Directory Publishing
Qwest Communications – Dex Sale	Arizona	ACC	T-0105B-02-0666	Staff	2003	Directory Publishing
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counsel	2003	Operating Income, Rate Trackers, Cost of Service, Rate Design
Qwest Communications	Arizona	ACC	T-0105B-03-0454	Staff	2004	Operating Income, Rate Base
Verizon Northwest	Washington	WUTC	UT-040788A	Attorney General	2004	Operating Income, Rate Base, Directory Imputation
Public Service Company of Oklahoma	Oklahoma	OCC	Cause No. 200300076	Attorney General	2005	Operating Income, Rate Base, Cost of Service, Rate Design
Hawaiian Electric Company, Inc.	Hawaii	PUC	04-0113	Consumer Advocate	2005	Operating Income, Rate Base, Cost of Service, Rate Design

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
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AND SUPPORTING SCHEDULES

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CA-T-2
DOCKET NO. 04-0113

DIRECT TESTIMONY AND EXHIBITS

OF

STEVEN C. CARVER

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Prepaid Pension Asset, Uncollectible Expense, Software costs, Office Leases, Demand Side Management, Rate Case Expense, Labor & Benefit Costs, Research & Development, Taxes Other, Income Taxes

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DIRECT TESTIMONY OF STEVEN C. CARVER

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven C. Carver. My business address is 740 NW Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a principal in the firm Utilitech, Inc., which specializes in providing consulting services for clients who actively participate in the process surrounding the regulation of public utility companies. Our work includes the review of utility rate applications, as well as the performance of special investigations and analyses related to utility operations, cost allocation and ratemaking issues.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. Hawaiian Electric Company, Inc. (hereinafter "HECO" or "Company") filed an application seeking the Public Utilities Commission of the State of Hawaii's ("Commission" or "HPUC") approval for an overall increase in the tariff rates and charges under which it provides regulated electric service on the island of Oahu. The HPUC opened Docket No. 04-0113 to review and address this application.

Utilitech was retained by the Department of Commerce and Consumer Affairs, Division of Consumer Advocacy (hereinafter "Consumer Advocate," or

"CA") to review and respond to that rate case filing and to prepare direct testimony for filing with this Commission regarding the issues identified during the course of our review. Consequently, I am appearing on behalf of the Consumer Advocate.

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

A. Generally, my responsibilities in this docket encompass the review and evaluation of various elements of rate base and operating income included within the overall revenue requirement, focusing on several functional expense categories: transmission & distribution, customer accounts, customer service, administrative and general, as well as taxes other than income taxes and income tax expense. As a result, I address various adjustments to rate base and operating income (CA Adjustments B-7, B-10 and C-13 through C-27) and jointly sponsor the Consumer Advocate's proposed capital structure (Schedule D) with Mr. David Parcell (CA-T-4). The additional ratemaking adjustments proposed by the Consumer Advocate, which I do not sponsor, are separately addressed in the direct testimony of Mr. Michael Brosch (CA-T-1). The revenue requirement effect of the various Consumer Advocate adjustments and recommendations are reflected within the Consumer Advocate's Joint Accounting Schedules (Exhibit CA-101).

I. EDUCATION AND EXPERIENCE.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated from State Fair Community College, where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE IN THE FIELD OF UTILITY REGULATION.

A. My entire professional career has been associated with the regulation of public utilities. From 1977 to 1987, I was employed by the Missouri Public Service Commission ("MoPSC") in various professional auditing positions, including a promotion by the Missouri Commissioners to the position of Chief Accountant in April 1983. Since my employment with Utilitech in June 1987, I have been associated with various regulatory projects on behalf of clients in multiple State jurisdictions (Arizona, California, Florida, Hawaii, Kansas, Illinois, Iowa, Indiana, Mississippi, Missouri, Nevada, New Mexico, New York, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia and Wyoming) and have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water). Additional information regarding my professional experience and qualifications are summarized in Exhibits CA-200 and CA-201, which have been prepared for this purpose.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION IN PROCEEDINGS THAT INVOLVED HECO OR ITS SUBSIDIARIES?

A. Yes. Mr. Michael Brosch, also of Utilitech, and I prepared and presented revenue requirement recommendations in HECO's 1994 rate case (Docket No. 7700) on behalf of the Consumer Advocate. I have also prepared testimony in two proceedings involving Hawaii Electric Light Company (Docket Nos. 98-0013 and 99-0207), a HECO subsidiary. In addition, I have prepared testimony in several other Hawaii regulatory proceedings, including: Kauai Electric, a Division of Citizens Communications Company (Docket No. 94-0097); GTE Hawaiian Telephone Company, Inc. (fna Verizon Hawaii, nka Hawaiian Telcom) (Docket No. 94-0298); The Gas Company (Docket No. 00-0309); as well as a self-insured property damage reserve generic proceeding (Docket No. 95-0051), in which HECO and its subsidiaries participated.

Finally, I have assisted the Consumer Advocate in its analysis of the acquisition of The Gas Company by Citizens Communications Company from Broken Hill Proprietary Company, Ltd. (Docket No. 97-0035) and the subsequent acquisition of The Gas Company, a Division of Citizens Communications Company by K-1 USA Ventures, Inc. (Docket No. 03-0051), as well as the analysis of the sale of Verizon Hawaii to entities controlled by the Carlyle Group (Docket No. 04-0140).

II. EXECUTIVE SUMMARY.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RESPONSIBILITIES IN THIS PROCEEDING?

A. My testimony addresses various issues surrounding the reasonableness of HECO's proposed rate increase and discusses specific rate base and operating income adjustments that I will generally refer to as "CA Adjustments" or "CA Schedules," which are set forth within a separate bound volume identified as Exhibit CA-101. These CA Adjustments and CA Schedules affect various operations and maintenance ("O&M") expense and rate base components upon which base rates are to be determined in the instant proceeding.

The ratemaking adjustment areas I address include: the removal the pension asset from rate base, software project costs, ratemaking recognition of office lease costs, adjustments to the test year employee counts and standard labor rates, removal of demand side management program costs and adjustment of the IRP general planning costs, normalization uncollectible expense, research and development costs, income tax expense and deductible interest expense. The specific adjustments are more fully listed in the index to my testimony.

Q. HOW WILL YOU IDENTIFY AND REFER TO THE INDIVIDUAL ACCOUNTING ADJUSTMENTS?

A. As discussed by Mr. Brosch, the rate base and operating income adjustments have been numbered sequentially, but separately, beginning with the number "one." In order to distinguish the first rate base adjustment from the first operating income adjustment, the adjustment number is preceded by a reference to the schedule on which the adjustment was posted. So, the first rate base adjustment would be referenced as CA Adjustment B-1 and the first operating income adjustment would be identified as CA Adjustment C-1. Mr. Brosch and I may use the words "schedule" and "adjustment" interchangeably when referring to the individual adjustments proposed by the Consumer Advocate.

Q. DO THE JOINT ACCOUNTING SCHEDULES PROVIDE CALCULATION DETAIL SUPPORTING EACH CONSUMER ADVOCATE ADJUSTMENT?

A. Yes. The joint accounting schedules contain individual adjustment "schedules" that typically show the quantification of each adjustment, with footnote reference to supporting documentation. Virtually all information relied upon by the Consumer Advocate in developing these adjustments was supplied by HECO in response to written discovery or contained in Company workpapers. Consequently, the adjustment schedules generally refer to relevant data sources, already in the Company's possession.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. My testimony is arranged by topical section, following the table index presented previously. This index identifies the specific areas I address in testimony and references the testimony pages as well as any related adjustment support located in the joint accounting schedules.

III. PREPAID PENSION ASSET.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT B-10?

A. CA Adjustment B-10 (Exhibit CA-101) eliminates from rate base HECO's proposed inclusion of a pension asset. This adjustment also removes the related accumulated deferred income tax ("ADIT") reserve from rate base.

Q. WHAT IS THE AMOUNT OF PENSION ASSET THAT HECO PROPOSES TO INCLUDE THE TEST YEAR RATE BASE?

A. In direct testimony, Company witness Ohasi (HECO T-19) proposed to include in rate base an estimated average prepaid pension asset balance of about $65.9 million,[1] gross of the related ADIT reserve balance. HECO subsequently revised its test year forecast of the average prepaid pension

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[1] HECO T-19, p. 10 & HECO-1904.

asset to $78.8 million, in response to several of the Consumer Advocate's information requests.[2]

Q. WHAT PENSION ASSET AMOUNT DOES THE CONSUMER ADVOCATE ADJUSTMENT REMOVE FROM HECO'S PROPOSED RATE BASE?

A. CA Adjustment B-2 (Exhibit CA-101) updates the components of rate base "other" than net plant to recognize HECO's revised forecast, an adjustment sponsored by Mr. Brosch (CA-T-1).

Because of this "update," the Consumer Advocate must remove the Company's adjusted net pension asset projection from rate base for the reasons that will be discussed in Section III.B. herein. Thus, CA Adjustment B-10 removes the pension asset by decreasing rate base by $78.8 million. As will be discussed in Section III.C. of my testimony, CA Adjustment B-10 also increases rate base by $28.5 million to remove the related average ADIT reserve balance.[3] The net effect of both elements of this adjustment is to reduce rate base by $50.3 million, as shown on CA Adjustment B-10.

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2 See HECO responses to CA-IR-98, CA-IR-337, CA-IR-691 and DOD/HECO-IR-10-4.

3 See HECO responses to CA-IR-356 (revised 5-26-05) and DOD/HECO-IR-4-4 for the average ADIT reserve balance.

Q. HAVE YOU ADDRESSED THIS ISSUE IN PAST RATE PROCEEDINGS?

A. Yes. I have sponsored testimony in various jurisdictions opposing the inclusion of a pension asset in rate base, including:

Jurisdiction	Case / Docket	
Arizona Corporation Commission	E-1051-93-183	(a)
	T-1051B-99-105	(a)
	T-1051B-03-0454	(c)
Public Utilities Commission of Hawaii	94-0298	(e)
Oklahoma Corporation Commission	PUD 001151	(d)
Utah Public Service Commission	97-049-08	(a)
Washington Utilities & Transportation Commission	UT-930074	(b)
	UT-040788	(f)

Note (a): Qwest Corp. rate case.
Note (b): Qwest Corp. AFOR – sharing.
Note (c): Qwest price cap review.
Note (d): Oklahoma Natural Gas.
Note (e): GTE Hawaiian Tel.
Note (f): Verizon Northwest rate case.

Q. IN THE PROCEEDINGS IDENTIFIED IN THIS TABLE, DID YOU RECOMMEND THE COMPLETE ELIMINATION OF THE PENSION ASSET FROM RATE BASE?

A. Yes, except for the most recent Qwest Corporation proceeding in Arizona (ACC Docket No. T-1051B-03-0454). In the remaining dockets, my pension asset analyses resulted in recommendations excluding the pension asset from rate base. However, in the recent Arizona Qwest proceeding, the update of my earlier analyses did support, for the first time, the inclusion of the pension asset in rate base. Absent a demonstration that ratepayers have materially participated in the cumulative pension credits or reduced pension costs comprising the pension asset, my analyses have fairly consistently questioned whether the alleged benefits were instead enjoyed by investors, not ratepayers.

A. BACKGROUND REGARDING PENSION COST ACCOUNTING.

Q. PLEASE DESCRIBE THE EVENTS OR CIRCUMSTANCES GIVING RISE TO THE PENSION ASSET.

A. In December 1985, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 87 ("FAS87"). FAS87 provided guidance as to how companies would recognize pension costs for financial statement reporting purposes, effective for fiscal years beginning after December 15, 1986. Prior to the issuance of FAS87, the amount of pension costs recorded by a company was equal to the level of contributions actually made to the pension fund. As a result of FAS87, the FASB determined that pension costs reported in public financial statements would not automatically be equal to the pension fund contribution, breaking the historical linkage between financial reporting of net periodic pension costs (expense and capital) and pension contributions.

If the pension fund contribution exceeded the pension costs recorded for financial statement purposes,[4] FAS87 required the difference to be recorded in a pension asset or prepaid account. If the contribution was less

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[4] Pension costs recorded for financial statement purposes pursuant to FAS87 are also referred to as "net periodic pension costs" or "NPPC."

than the recorded pension cost, the company would record a pension obligation or liability. In sum, FAS87 required companies to record either a pension asset or pension liability for the difference between accrual basis pension costs and the amount of any contributions to the pension fund. This accounting is commonly referred to as "net periodic pension cost" ("NPPC") accounting.

Q. HOW DID THE ISSUANCE OF FAS87 AFFECT THE PENSION COSTS RECORDED ON THE COMPANY'S FINANCIAL STATEMENTS?

A. Subsequent to the adoption of FAS87, HECO's pension costs continued to equal the amounts contributed to the pension fund in each year until 1995.[5] Beginning in 1995, the contributions to the fund exceeded the amount recorded for financial statement purposes under NPPC accounting, thereby causing HECO to record a pension asset. This situation continued through 1998. As a result, HECO recorded a relatively modest pension asset during the period 1995 through 1998, with an asset balance of only $335,979 at the end of that period.

In 1999, however, the pension costs recorded for financial statement purposes pursuant to FAS87 became negative (i.e., pension credits), rather than "positive" amounts as were recorded in prior years. Although HECO

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5 HECO's pension asset accounting is summarized on Exhibit CA-202.

made no contribution to the pension fund in 1999, "zero" still exceeded the negative pension costs and the prepaid pension asset account grew significantly. From 1999 through 2004, the Company recorded negative pension costs in five years and made no contribution to the pension fund in five years. Thus, under FAS87 accounting, the actual prepaid pension asset balance grew from only $335,979 at December 1998 to $81.1 million at December 2004.

It is the accumulation of contributions to the pension fund in excess of FAS87 determined pension costs that caused the pension asset balance to accumulate to an average of $78.8 million in the forecast test year. [See Exhibit CA-101, CA Adjustment B-10, and Exhibit CA-202.]

B. PROPOSED HECO APPROACH.

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM THAT THE PREPAID PENSION ASSET SHOULD BE INCLUDED IN RATE BASE?

A. At page 11, HECO T-19 generally summarizes the Company's basis for seeking rate base inclusion as follows:[6]

> In theory, ratepayers provide the funds based on the NPPC and investors provide the funds contributed to the pension fund. The prepaid pension asset is the net of the NPPC and the funds contributed to the pension fund. Since the test year estimates forecast that the NPPC and fund contributions will result in a net

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6 "NPPC" refers to "net periodic pension cost" recorded in conformance with generally accepted accounting principles. As set forth on Exhibit CA-202, the primary factor causing HECO's large prepaid pension asset balance is the recording of negative NPPC, or pension credits, during the period 1999-2004.

> asset, investors are providing the net amount. Since investors are entitled to earn a return on these funds, this asset is appropriately included as an addition to rate base. This was the result in HELCO's 2000 test year rate case. See Decision and Order No. 18365 (dated February 8, 2001) in Docket No. 99-0207.

In essence, the Company's rationale for rate base treatment appears to be premised on the belief that relative amounts were provided by ratepayers and investors as follows: (a) ratepayers provide funds equal to the pension costs recorded for financial statement purposes; and (b) investors provide funds equal to the amounts contributed to the pension fund. Based on this premise, HECO claims that the prepaid pension asset should be included in rate base since recorded pension costs are less than pension contributions -- investors having advanced more funds than provided by ratepayers.

Q. CAN YOU EXPLAIN THE BASIS FOR HECO'S DETERMINATION THAT RATEPAYERS PROVIDE PENSION COSTS BASED ON THE NPPC?

A. This question was posed to HECO as CA-IR-353(b). In response, HECO stated:

> The NPPC is used to determine the administrative and general expenses charged to O&M and used to determine revenue requirements. See testimony of Ms. Julie Price, HECO T-15, pages 5 and 6 and HECO-1502.

Company witness Price (HECO T-15) does point out at page 5 that the Commission has used NPPC in determining overall revenue requirements for HECO, HECO and MECO, since FAS87 became effective in 1987.

C. PROPOSED CONSUMER ADVOCATE APPROACH.

Q. WHAT IS THE CONCERN WITH HECO'S ASSUMPTION THAT RATEPAYERS PROVIDE FUNDS EQUAL TO THE PENSION COSTS RECORDED ON THE FINANCIAL STATEMENTS AND INVESTORS PROVIDE AMOUNTS CONTRIBUTED TO THE PENSION FUND?

A. There simply is no basis for HECO's assertion that ratepayers only provide funds equal to <u>recorded</u> pension costs and any excess monies contributed to the pension fund come from HECO's investors.

Q. PLEASE EXPLAIN WHY.

A. The financial accounting requirements under FAS87 were neither designed nor intended to quantify the amount of pension costs regulated entities recover from their customers. Instead, FAS87 sets forth the required framework for all publicly traded companies to quantify and record net periodic pension costs. HECO seems to attempt to equate FAS87 cost recognition with ratepayer recoveries, without providing any evidence to substantiate that claim.

As demonstrated by Exhibit CA-202, the primary reason that cumulative pension contributions have exceeded recorded pension costs is because the financial accounting requirements of FAS87 have resulted in HECO recording significant pension credits. Thus, the $58 million of negative pension costs recorded in calendar years 1999-2002 and 2004 were merely the result of the

FAS87 financial accounting requirements and have nothing to do with "who" (ratepayers or investors) provided the monies contributed to the pension fund.

Q. THE EARLIER QUOTE FROM PAGE 11 OF HECO T-19 INDICATED THAT THE RATE BASE INCLUSION OF THE PENSION ASSET WAS CONSISTENT WITH HELCO'S 2000 TEST YEAR RATE CASE. IN YOUR OPINION, DO PAST "DETERMINATIONS" BY THE COMMISSION DEMONSTRATE THAT RATEPAYERS PROVIDE FUNDS TO THE UTILITY EQUAL TO THE PENSION COSTS BASED ON NPPC ACCOUNTING?

A. No, at least not in the context HECO uses NPPC accounting in an attempt to include the pension asset in the test year rate base for the instant proceeding.

Q. AS YOU INDICATED PREVIOUSLY, EXHIBIT CA-202 SHOWS THAT HECO RECORDED OVER $58 MILLION OF NEGATIVE PENSION COSTS SINCE 1999. DOES THE MERE FACT THAT HECO RECORDED THE NEGATIVE NPPC, OR PENSION CREDITS, RESULT IN AN AUTOMATIC AND SUBSTANTIAL BENEFIT TO RATEPAYERS IN THE FORM OF DECREASED COSTS?

A. No. Under traditional regulation, utility rates are based on a test year cost of service, theoretically designed to balance the various components of the ratemaking equation. Once determined, those rates are generally considered just and reasonable until rates are subsequently revised in a formal proceeding. In general terms, the utility is considered to have recovered all costs incurred between rate cases and achieved a reasonable return on its rate base investment.

However, it is not uncommon for regulators to be presented with various issues associated with accounting changes (e.g., transition from pay-as-you-go to FAS106 accrual accounting for OPEB costs, capitalization of software development costs), cost deferrals (e.g., storm damage, demand-side management costs), amortization requests (e.g., depreciation reserve deficiency, workforce reduction program costs) or tracking mechanisms (fuel adjustment clause, demand-side management costs) that deviate from this general framework. If the mere recording of a transaction meant that ratepayers symmetrically funded increases and benefited from decreases in expense, there would seem to be no need for the many deferral, cost tracker or amortization issues that frequently arise in utility regulation. The fact is that such issues do arise and have existed for many years. Rather than dismissively reject these requests, regulators typically review the facts and circumstances unique to each situation and determine whether the regulatory treatment requested by the utility should be accepted, rejected or modified.

The pension asset is no different. While negative pension costs or credits have been recorded by some utilities since the late 1980's, the question in the current proceeding should focus on whether HECO's ratepayers have benefited from the reduced pension costs, in comparison to pension contributions, to support rate base inclusion of the pension asset. In other words, have negative pension costs (or pension costs below pension contribution levels) been reflected in the cost of service or somehow separately flowed through to customers "as recorded" each year since the adoption of FAS87? If ratepayers have not benefited from the reduced level of pension costs, as compared to contributions, then the Company and its investors are the only remaining parties that could have benefited from the reduced costs through higher earnings than would have otherwise been achieved.

While the Company has proposed to include the pension asset in rate base, HECO has provided no factual support that utility rates have been materially understated or that ratepayers have somehow improperly been advantaged to the detriment of HECO's investors. Rate base inclusion is appropriate only if it can be reasonably demonstrated that reduced FAS87 pension costs, including the pension credits, on a cumulative basis in an amount at least equal to the prepaid pension asset have been flowed through to the benefit of HECO's ratepayers.

Q. DO YOU BELIEVE THAT RATEPAYERS RECEIVE THE BENEFIT OF PENSION CREDITS MERELY AS A RESULT OF RECORDING THE NEGATIVE PENSION COSTS?

A. No. The mere recording of NPPC, whether positive or negative in amount, at levels lower than pension contributions does not conclusively demonstrate "who" may have funded, or benefited from, the lower recorded pension costs (or pension credits). Since HECO has sought rate base treatment of the pension asset, the Company should bear some burden to demonstrate that such inclusion is proper.

Q. DOES THE COMPANY BELIEVE THAT RATEPAYERS RECEIVE THE BENEFIT OF PENSION CREDITS MERELY AS A RESULT OF RECORDING THE NEGATIVE PENSION COSTS?

A. CA-IR-354(b) asked the Company whether the "act of recording negative NPPC results in those credits automatically being flowed through to the benefit of customers." In response, HECO stated: "No, the Company does not believe that there is any automatic flow through to ratepayers of any negative NPPC." I concur, but would go one step further. I also do not believe that ratepayers receive any automatic benefit in those years wherein NPPC is lower than actual pension fund contributions. Nevertheless, HECO has proposed to include in rate base the cumulative amount of pension contributions in excess of NPPC.

Absent some attempt to assess ratepayer participation in those cumulative pension benefits, either through pension credits or lower NPPC, HECO's rate base proposal would charge ratepayers with a rate base return on funds they may have never received or benefited from – unnecessarily benefiting the Company and its investors.

Q. HAVE THE PENSION CREDITS, OR PENSION COSTS BELOW CONTRIBUTIONS, RESULTED IN HIGHER EARNINGS?

A. Yes. Under FAS87, regulated utilities record pension costs in an amount equal to NPPC, unless ordered otherwise by regulators. If reduced or even negative levels of NPPC are not automatically flowed through to the benefit of customers via bill credits or rate reduction, the resulting decrease to operating expense would increase HECO's net operating income above levels that would have been realized absent FAS87.

Q. REFERRING TO EXHIBIT CA-202, HOW DOES THE AMOUNT OF PENSION COSTS INCLUDED IN HECO'S COST OF SERVICE IN THE LAST RATE CASE COMPARE TO THE NPPC SUBSEQUENTLY RECORDED BY THE COMPANY?

A. Although it is not possible to precisely quantify the amount of accumulated net pension recoveries from or benefits provided to ratepayers following the adoption of FAS87, it is possible to perform a simple analysis comparing the level of pension costs included in rates in Docket No. 7766 with the NPPC subsequently recorded by HECO, in order to evaluate whether ratepayers might have received any material benefit from the reduced NPPC, thereby supporting HECO's proposed rate base treatment.

Referring to HECO's response to CA-IR-355, the Company's last rate case was based on a 1995 test year, which included the following NPPC forecast estimates: $11.1 million (direct testimony) and $10.6 million (rebuttal testimony). According to this interrogatory response, the pension contribution forecast for the 1995 test year was equal to these NPPC amounts. Consequently, the difference between NPPC and pension contributions in the last rate case was "zero." Since HECO's base rates have not been revised since the 1995 rate case and about $10.6 million of NPPC was included in the revenue requirement used to establish existing tariff rates, HECO has theoretically recovered about $10.6 million of NPPC from ratepayers on an annual basis, all else remaining constant.

Referring to Exhibit CA-202, substantially all of the prepaid pension asset HECO seeks to include in rate base has arisen since 1995,[7] including about $58 million of pension credits that, by my estimation, have never been flowed through to ratepayers. In comparison, HECO has recovered from

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[7] HECO's revised average pension asset for the 2005 forecast is $78.8 million. $2.7 million of that cumulative average forecast balance arose in 1995. Since Decision and Order No. 14412 (Docket No. 7766) was issued on December 11, 1995, $76.1 million ($78.8 million minus $2.7 million) or substantially all of the prepaid pension asset has arisen since 1995.

ratepayers about $10.6 million of NPPC per year for ten years or $106.0 million, assuming a rate order in the pending docket near year-end 2005. During this same ten-year period, Exhibit CA-202 indicates that HECO's total pension contributions have been $43.6 million – only about 41%[8] of the estimated NPPC collected from ratepayers.

Since the last rate case, HECO has theoretically recovered about $106 million in pension costs from ratepayers and contributed about $43.6 million to the pension fund, but seeks to include a $78.8 million pension asset in rate base. Given this information, it would appear that ratepayers have received absolutely no tangible "benefit" from HECO having recorded cumulative pension costs at levels less than pension contributions. Consequently, the pension asset should be properly excluded from rate base.

Q. ARE YOUR CALCULATIONS OF RECOVERIES FROM RATEPAYERS "EXACT" IN AMOUNT?

A. No. It is not possible to precisely quantify the "exact" amount of cumulative net pension recoveries from or benefits provided to ratepayers, particularly over the decades predating or following the adoption of FAS87. However, it is <u>reasonable</u> to consider relevant, available information to assess regulatory intent and estimate the amount of cumulative pension costs or credits that

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8 $43.6 million pension contributions divided by $106.0 million estimated NPPC recovered from ratepayers.

might have been reasonably recovered from or otherwise flowed through to the benefit of ratepayers, in the context of HECO's stated theoretical basis for including the pension asset in rate base. After all, HECO began recording a pension asset in 1995 as a result of the decoupling of pension cost and pension contributions, pursuant to FAS87.

Q. BY ATTEMPTING TO ASSESS RATEPAYER PARTICIPATION IN THE REDUCED PENSION COSTS RECORDED BY THE COMPANY OVER THE YEARS, ARE YOU SUGGESTING THAT THE COMMISSION ENGAGE IN RETROACTIVE RATEMAKING?

A. No, absolutely not. I do not propose or suggest that HECO should pay back past excessive profits or recoup past operating losses, as implied by that concept. Instead, the retrospective analysis or review that I propose would solely be used to gauge the extent of benefits received by ratepayers or retained by investors in determining whether the pension asset balance should be included in rate base.

Q. HAS YOUR APPROACH BEEN USED FOR ANY OTHER ELEMENT OF RATE BASE?

A. No, it has not. However, such a criticism fails to address the key points of concern relative to this issue:

- Have ratepayers benefited from the pension credits or recorded NPPC less than contribution levels?
- If so, by how much?
- Is the cumulative extent of any benefits enjoyed by ratepayers sufficient to include the pension asset in rate base?

The implementation of FAS87 resulted in a significant shift in accounting method for pension costs from the cash basis to an accrual basis. Because this shift caused HECO to record pension costs at levels significantly less than pension contributions, including pension credits, I believe that it is responsible and reasonable for regulators to question the extent to which ratepayers, not the Company and its investors, have enjoyed the benefits of those annual pension credits – before allowing the pension asset in rate base.

Q. WHY IS THAT?

A. All components of the ratemaking equation change over time – revenues, expenses and investment. As each component changes, a utility should have a reasonable opportunity to achieve its authorized return (i.e., not materially over or under earn), so long as the components remain in relative balance or changes to one component are mitigated or offset by changes in other components. I generally agree that the prohibition against retroactive ratemaking presumes that recorded costs are assumed to be recovered, regardless of explicit inclusion in cost of service. This presumption holds the utility accountable for incurred costs and prevents a potentially abusive process of collecting past earnings deficiencies from current and future ratepayers.

Since adoption of FAS87, the amount of pension costs and pension credits recorded by HECO has varied significantly from year-to-year.[9] In the absence of rate case activity or some mechanism to flow the reduced NPPC, or pension credits, through to benefit ratepayers, FAS87 pension accounting has resulted in the reduced NPPC increasing utility income and investor returns.[10]

Contrary to any implications otherwise, the evaluation of this issue is not designed, intended nor does it result in a retrospective inquiry of past earnings to impose a surcharge for past under-recoveries or a refund for past over-recoveries. Instead, this approach is designed to evaluate, based on available information, whether it is reasonable to assume that ratepayers have sufficiently enjoyed the benefits of the ever fluctuating NPPC (supporting rate base inclusion of some portion of the pension asset) or whether the resulting earnings benefits have been retained by investors (supporting the rate base

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9 The amount of NPPC recorded since 1987 has ranged from a $11.4 million in 1992 to $(20.5) million in 2001 (HECO response to CA-IR-337).

10 Since the 1995 rate case, Exhibit CA-202 (Column B) shows that HECO has not recorded anywhere near $10.6 million of pension costs in any calendar year – even though that amount was included in determining overall revenue requirement in that rate proceeding.

exclusion). Exhibit CA-202 compares the amount of annual NPPC with pension contributions, dating back to 1987.

Q. DO YOU BELIEVE THAT ALL ELEMENTS OF THE COST OF SERVICE INCLUDED IN PAST RATES SHOULD BE RECONCILED WITH CURRENT COST LEVELS TO DETERMINE PROSPECTIVE RATE TREATMENT FOR EACH ITEM?

A. No. As a matter of ratemaking policy, I do not recommend that the Commission rely solely on or otherwise reconcile past decisions in establishing cost of service for future periods. However, the consideration of past rate orders is indeed relevant in assessing whether investors have some reasonable claim to inclusion of the pension asset in rate base. As discussed above, I recommend that the Commission <u>exclude</u> the pension asset from rate base.

Q. IN THE 2005 TEST YEAR FORECAST, HAS HECO ESTIMATED NPPC TO BE POSITIVE OR NEGATIVE AND HOW DOES THAT AMOUNT COMPARE TO THE ESTIMATED PENSION CONTRIBUTION?

A. According to the responses to CA-IR-339(a) and DOD/HECO-IR-9-2, HECO currently forecasts the 2005 NPPC at a level in excess of $4 million and does not anticipate any pension fund contribution. While the 2005 funding will be reviewed in the fourth quarter of 2005,[11] the amount of pension costs included in overall revenue requirement exceeds planned contributions for the year, which caused the December 2005 estimated pension asset balance to be lower than the December 2004 actual balance.

D. ADIT RELATED TO THE FAS87 PENSION ASSET.

Q. PLEASE EXPLAIN WHY A FURTHER ADJUSTMENT TO REMOVE THE ADIT RESERVES ASSOCIATED WITH THE PREPAID PENSION ASSET IS NECESSARY AND SHOULD BE ADOPTED BY THE HPUC IF THE COMMSSION ADOPTS CA ADJUSTMENT B-10 TO REMOVE THE PREPAID PENSION ASSET FROM RATE BASE.

A. The prepaid pension asset set forth on HECO-1904, as revised, does not recognize, or is shown gross of, the accumulated deferred income tax reserves that are associated with the prepaid asset. These reserves reflect the accumulated deferred income taxes that are associated with the tax timing difference resulting from the differing amounts recorded as pension costs on the financial statement and the contributions deducted on the income tax return of HECO. Thus, for consistency purposes, if the Company's prepaid pension asset is to be excluded from rate base, the companion ADIT reserve should be similarly removed.

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11 See HECO's response to CA-IR-339(a).

IV. UNCOLLECTIBLE EXPENSE.

Q. WHAT IS CA ADJUSTMENT C-13?

A. CA Adjustment C-13 (Exhibit CA-101) quantifies uncollectible, or bad debt, expense for the forecast test year based on an historical ratio of net bad debt write-offs ("net write-offs") to electric revenues. This bad debt ratio is applied to the Consumer Advocate's pro forma electric revenues in order to incorporate an ongoing level of uncollectible expense of about $1.18 million in overall revenue requirement. As a result of our analyses of the uncollectible data supplied by HECO, the Consumer Advocate has not included a bad debt ratio in the calculation of the gross revenue conversion factor, as presented on CA Adjustment A-1 (Exhibit CA-101).

Q. WHAT LEVEL OF UNCOLLECTIBLE EXPENSE HAS HECO PROPOSED TO INCLUDE IN THE 2005 TEST YEAR FORECAST?

A. As discussed by Company witness Yamamoto (HECO T-9),[12] HECO has included $1,292,000 of uncollectible expense in the 2005 test year forecast, at present rates, which is increased to $1,419,000 at proposed rates.

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[12] HECO has indicated that the direct testimony originally filed by Ms. Amy E. Ejercito (HECO T-9) will be adopted and sponsored by Mr. Darren Yamamoto.

Q. HOW DID HECO DETERMINE THESE UNCOLLECTIBLE AMOUNTS?

A. According to HECO T-9, page 20, the Company generally utilized the "percentage of electric sales revenue" method accepted by the Commission in past rate case proceedings.[13] Using the then most recent historical data for the twelve-month period ending April 2004, HECO calculated an uncollectible percentage, or ratio, of 0.10%, illustrated as follow:

	Amount	Ratio
Net Write-Offs (12ME 4/04)	$965,424	
Electric Sales Revenues (2003)	$960,716,973	0.1005%
Total Operating Revenues (2003)	$963,500,496	0.1002%

Sources: HECO response to CA-IR-75 & 2003 FERC Form 1.

However, HECO T-9, page 20, indicates that the Company used an uncollectible rate of 0.13% of revenue, which is 30% higher than the historical rate, to calculate uncollectible expense for the 2005 forecast test year.

Q. WHY DID HECO USE THE MUCH HIGHER 0.13% RATE?

A. HECO T-9, page 20, offers the following explanation:

> Over the past several years, the economy has not recovered as completely as expected. We anticipate continued large to mid-size commercial customer bankruptcies that are not within our control; attributable to recent openings of retail giants in Hawaii which impact surrounding or similar businesses.

[13] The "percentage of electric sales revenue" method produces an uncollectible percentage that is quantified by dividing total net write-offs by total electric sales revenue, lagged by four months.

In order to obtain further information regarding these representations, CA-IR-75 was submitted for several purposes. First, this information request sought historical levels of gross write-offs and recoveries by month for the period January 2000 through December 2004. Using this information, the Consumer Advocate would be able to analyze relatively recent write-off activity before and after the down turn in Hawaii's travel industry, as a result of the September 11, 2001 ("9/11") terrorist attack.

Second, CA-IR-75 also requested the write-off activity separately for residential and commercial accounts. This segregated data would enable the Consumer Advocate to assess relative changes in commercial and residential write-off activity during this five-year period. However, HECO declined to produce this information, instead providing combined write-off activity. As a result, the Consumer Advocate is unable to discern any historical trends unique to commercial account write-offs.

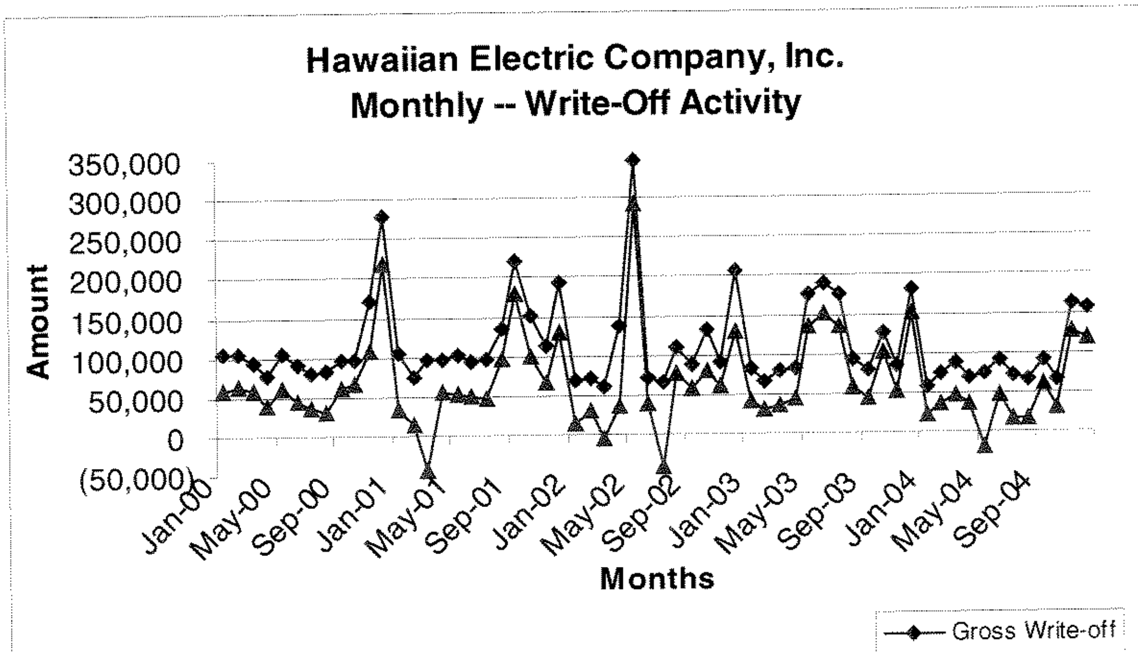
Q. IN DIRECT TESTIMONY, DID HECO PRESENT ANY EVIDENCE THAT COMMERCIAL ACCOUNT BANKRUPTCIES HAD INCREASED TO SUCH AN EXTENT TO SUPPORT THE 0.13% BAD DEBT RATE?

A. The only uncollectible evidence presented by the Company is set forth on HECO-905, HECO-906 and HECO 907. HECO-905 simply shows the Company's calculation of uncollectible expense for the forecast test year. HECO-906 represents an historical comparison of the favorable decline in uncollectibles as a percent of revenues for the period 1982-2004, showing relative stability near 0.10% since calendar year 2000. HECO-907 represents two charts showing an increase in third quarter 2004 residential and commercial accounts outstanding for 60 days or more.

However, in response to CA-IR-681(e), HECO provided the calculation details underlying the Company's proposed 0.13% uncollectible factor. Based this documentation, the 0.13% uncollectible factor is the sum of net write-offs divided by the sum of sales revenues for the period January 1995 through April 2004 – a period of 112 months or 9.33 years. Referring to the Company's chart depicting historical net write-offs as a percent of revenues (HECO-906), this 112-month period includes the clearly evident upward "bulge" in the uncollectible factor in the mid to late 1990's – depicting a level of uncollectible ratio not repeated since 1999. HECO has present no evidence demonstrating that the Company will experience an ongoing uncollectible rate of 0.13% for the foreseeable future.

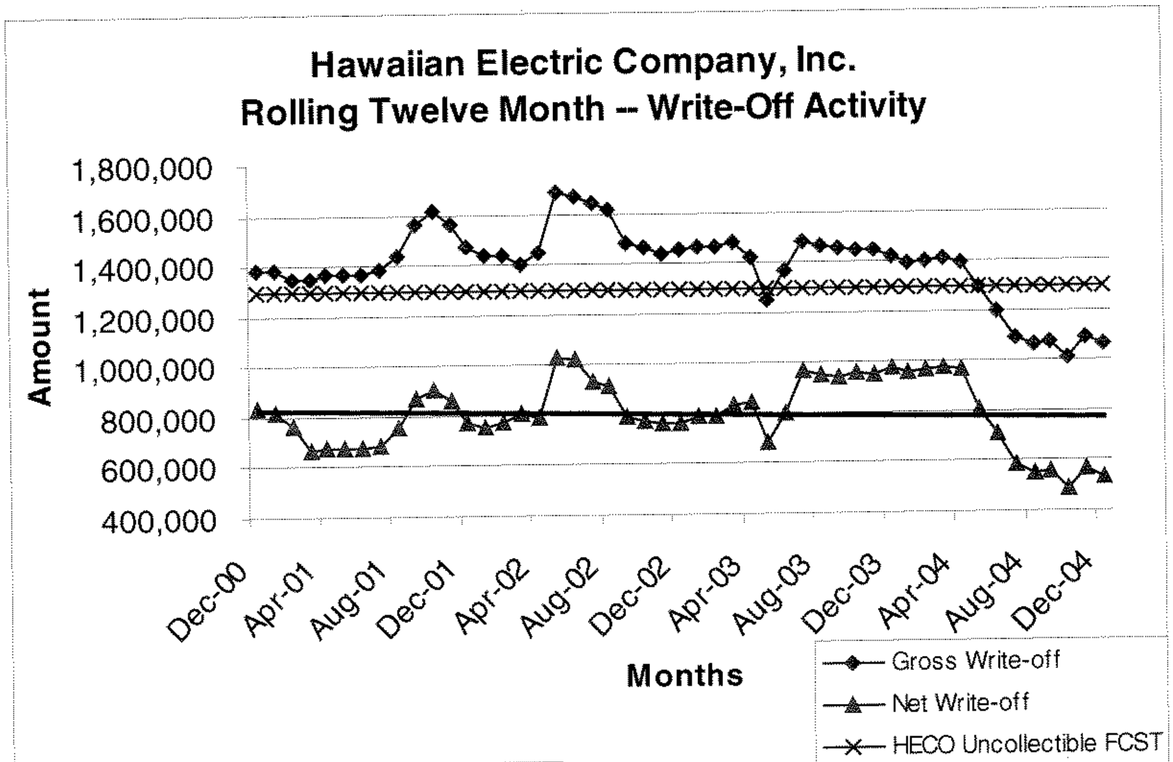
Q. DOES ACTUAL NET WRITE-OFF ACTIVITY IN 2004 APPEAR TO SUPPORT HECO'S REQUESTED 30% INCREASE IN THE UNCOLLECTIBLE RATE FROM 0.10% TO 0.13%?

A. No. The following graph presents gross and net write-off activity on a monthly basis. While the write-off activity in November and December 2004 does increase relative to the other months of 2004, the increase is not out of line with other months in this five-year historical period.



Source: HECO response to CA-IR-75.

In order to smooth out the month-to-month variability in write-off activity, the following graph examines the same data set, instead focusing on rolling twelve-month periods to smooth out the monthly variations and identify any trends in the underlying write-off data.



Source: HECO response to CA-IR-75.

During this five-year period, net write-offs have generally ranged between $600,000 and $1,000,000, dipping below $600,000 in the latter part of 2004. The net write-off trend line (designated as "Linear" on the chart) shows a slight decreasing trend near $800,000 on an annual basis. In comparison, HECO's proposed $1,292,000[14] of uncollectible expense, based on 0.13% of 2005 forecast revenues, is more closely associated with the level of gross write-offs during this five-year period.

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14 The $1,292,000 is before recognizing additional uncollectibles on the requested rate increase, which increases the overall level of uncollectible expense sought by HECO to $1,419,000.

Q. HOW DID THE CONSUMER ADVOCATE DETERMINE THE UNCOLLECTIBLE EXPENSE FORECAST FOR PURPOSES OF CA ADJUSTMENT C-13?

A. During the period 2000-2004, HECO's actual net write-offs have averaged about $777,000. As a percent of revenues, the actual net write-offs have averaged about 0.0946%, excluding 2004. The following table summarizes the underlying data:[15]

	Net Write-Offs	Electric Sales Revenues	Total Operating Revenues	Electric Sales Ratio	Total Revenue Ratio
2000	$837,710	$832,703,418	$835,566,560	0.1006%	0.1003%
2001	774,636	901,109,340	904,038,912	0.0860%	0.0857%
2002	764,392	848,703,305	851,525,336	0.0901%	0.0898%
2003	975,434	950,236,663	952,970,294	0.1027%	0.1024%
2004	534,055	990,269,239	992,965,609	0.0539%	0.0538%
Average	$777,245	$904,604,393	$907,413,342	0.0859%	0.0857%
Average (excl 2004)	$838,043	$883,188,182	$886,025,276	0.0949%	**0.0946%**

Source: HECO response to CA-IR-75 & HECO revenues per monthly report.

Mindful of the earlier chart of rolling twelve month net write-off data trending around $800,000 per year and that 2004 net write-offs are significantly below that trend, I am recommending an uncollectible ratio of 0.0946%, based on a four-year average (2000-2003) net write-offs to total revenues. Calendar year 2004 was excluded from the calculation, because of the extremely low level of reported net write-offs. Referring to CA Adjustment C-13 (Exhibit CA-101),

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15 Net write-offs represent calendar year data, while revenues are lagged four months representing the twelve-month periods ending August.

this ratio is applied to the Consumer Advocate's 2005 total forecast revenue (under present rates) to derive a generous level of uncollectible expense, well above recent historical levels.

Q. WHY ARE REVENUES LAGGED BY FOUR MONTHS IN RELATION TO NET WRITE-OFF ACTIVITY?

A. As indicated by the response to CA-IR-75, HECO's collection practice allows a 90-day collection period prior to writing off an account and assigning it to a collection agency. Since customer meters are read on a monthly cycle basis, about 120 days transpire from the prior reading to an uncollectible account being written off. This four-month lag is consistent with the methodology adopted by the Commission in past rate proceedings.

Q. EARLIER, YOU INDICATED THAT THE CONSUMER ADVOCATE HAS NOT INCLUDED AN UNCOLLECTIBLE FACTOR IN THE CALCULATION OF THE GROSS REVENUE CONVERSION FACTOR. COULD YOU EXPLAIN THE BASIS FOR THAT EXCLUSION?

A. As indicated by the above chart, both electric sales revenues and total operating revenues are 18.9% higher in 2004 as compared to 2000, an increase of over $150 dollars. In comparison, the net write-offs in 2000 are higher than any subsequent year, with the exception of 2003. Although uncollectibles, or bad debts, are linked to operating revenues, the data for the most recent five years of historical data does not show the linear relationship required to demonstrate that any rate increase granted by the Commission will cause net write-offs to also increase. Absent such a demonstration, the gross revenue conversion factor should exclude a factor for uncollectibles.

Q. IF AN UNCOLLECTIBLE FACTOR WERE INCLUDED IN THE CALCULATION OF THE GROSS REVENUE CONVERSION FACTOR, WHAT WOULD BE THE AFFECT ON OVERALL REVENUE REQUIREMENT?

A. Revenue requirement would be increased under the presumption that the rate increase will produce additional write-offs – a presumption that is not supported by recent history.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON UNCOLLECTIBLES AND NET WRITE-OFFS?

A. Yes. As previously stated, the amount of net write-offs in calendar year 2004 ($534,055) is significantly below prior year levels.[16] It should be noted that before customer accounts are written off, the account is deemed to be delinquent. HECO T-9 has requested an increase in customer service staffing by nineteen (19) employees above the 2003 average level of 115 employees –

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16 HECO's response to CA-IR-682(b) actual attributes the decrease in 2004 write-off activity primarily to a drop in bankruptcies in 2004, as compared to prior years.

a 16.5% increase. It is possible that HECO may attribute the increase in delinquencies in the fourth quarter of 2004 (see HECO-907) to a lack of adequate manpower required to fully exhaust typical collection efforts and cut-off service to individual customers.

If true, the late-2004 delinquency increase may also partially explain the 2004 decline in net write-offs and could result in an increase in 2005 net write-offs, as the additional employees are hired by HECO. However, such an increase in 2005 net write-offs would not necessarily be indicative of ongoing activity, instead partially representing a catch-up of write-off activity that might have normally occurred in 2004.

In the event that HECO's rebuttal testimony continues to support an uncollectible rate of 0.13%, the Company should address the affect of 2004 manpower shortages in contributing to 2004 delinquency levels and 2005 write-offs. In addition, HECO should also provide historical trends in the average days accounts were delinquent and the related causes associated with any identified trends.

Q. YOU EARLIER INDICATED THAT HECO'S 0.13% UNCOLLECTIBLE FACTOR RESULTED IN FORECASTED BAD DEBT EXPENSE OF $1.29 MILLION, BEFORE CONSIDERING ANY RATE INCREASE. YOU ALSO STATED THAT THE CONSUMER ADVOCATE'S 0.0946% FACTOR PRODUCED $1.18 MILLION OF UNCOLLECTIBLE EXPENSE. WHY IS THE

DOLLAR DIFFERENCE SO SMALL IN RELATION TO THE MAGNITUDE OF THE DIFFERENCE IN UNCOLLECTIBLE FACTORS?

A. The Consumer Advocate's calculation of overall revenue requirement includes an adjustment synchronizing 2005 forecast revenue dollars with May 2005 fuel prices. As a result of this synchronization, CA Adjustment C-4 (sponsored by Mr. Brosch and supported by Mr. Herz) increases 2005 test year revenues by $250 million above HECO's proposed forecast level. This significant increase in revenues for the forecast test year has caused the Consumer Advocate's uncollectible expense forecast to be substantially higher than the level thus far recognized by HECO.

V. SOFTWARE COSTS.

Q. PLEASE DESCRIBE CA ADJUSTMENTS B-7 AND C-14.

A. CA Adjustments B-7 and C-14 (Exhibit CA-101) revise the ratemaking treatment of the cost of several software projects that HECO's original filing proposed to include in the 2005 test year forecast. The software programs addressed by these adjustments are summarized below:

- Human Resources Suite ("HRS"): Since HRS was not completed by test year-end, the project related costs were removed from rate base and operating expense.
- ELLIPSE Software: HECO's request to include costs in the 2005 test year for a possible 2007 software upgrade is removed and

the test year amortization of software maintenance buy-down fees expiring in May 2006 is removed from operating expense.

A. HUMAN RESOURCES SUITE ("HRS").

Q. PLEASE DESCRIBE THE HRS.

A. As discussed by Company witness Price (HECO T-15), HRS is a computer software system designed to better integrate benefits, human resources, compensation and disability management administration. At the time HECO filed its direct testimony, the Company was in the process of developing a request for proposal, with plans to identify a vendor by the end of 2004, and expected to implement Phase 1 of the project in 2005.[17]

Q. WHY SHOULD HRS BE REMOVED FROM THE 2005 FORECAST TEST YEAR?

A. During the course of this proceeding, the Consumer Advocate submitted several interrogatories to assess the ongoing status of the HRS software project, as HECO T-15 described the Company's intent to file an application with the Commission seeking project approval and deferral authority. In response to CA-IR-661, HECO stated that the "in-service date" for Phase I of

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[17] HECO T-15, p. 36.

the HRS project had been delayed into 2006 and that the amortization of the HRS development costs should be removed from the test year.

HECO's May 5 Update Letter[18] also indicated that the Company intended to revise "the amortization of HR Suites Software Development costs as discussed in response to CA-IR-352." Further, HECO's response to CA-IR-352 stated, in part: "If Phase 1 of the project cannot be implemented in the test year, $184,000 of the annual amortization of Phase 1 costs will be removed from Account 921 – A&G Expenses-Non-Labor and $369,000 of the average balance of unamortized system development costs (see HECO-1906) will be removed from rate base." CA Adjustments B-7 and C-14 recognize and adopt these proposed revisions.

B. ELLIPSE SOFTWARE.

Q. PLEASE DESCRIBE THE ELLIPSE SOFTWARE SYSTEM USED BY HECO.

A. The ELLIPSE software program is an enterprise resource planning ("ERP") solution offered by Mincom that HECO implemented in October 2003.[19]

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[18] In a letter dated May 5, 2005 ("May 5 Update Letter") to the Consumer Advocate and Department of Defense, HECO identified and described various updates and revisions the Company intends to recognize in its rebuttal filing.

[19] HECO response to CA-IR-80.

Q. COULD YOU SUMMARIZE THE TYPES OF ELLIPSE SOFTWARE COSTS INCLUDED IN HECO'S 2005 TEST YEAR FORECAST?

A. Yes. Company witnesses Mr. Ernest Shiraki (HECO T-13) and Ms. Tayne Sekimura (HECO T-16) discuss the various ELLIPSE software costs included in the forecast test year, including:

- Ellipse periodic software upgrades,
- Ellipse maintenance fees,
- BSI maintenance fees, and
- Ellipse buy-down fee/ amortization.

Q. IS THE CONSUMER ADVOCATE PROPOSING TO ELIMINATE ANY OF THESE SOFTWARE COSTS FROM HECO'S 2005 TEST YEAR FORECAST?

A. Yes. CA Adjustment C-14 removes HECO's forecast of the ELLIPSE software upgrade amortization as well as the ELLIPSE buy-down fee amortization.

Q. WHY SHOULD THE ELLIPSE SOFTWARD UPGRADE BE REMOVED FROM THE 2005 FORECAST TEST YEAR?

A. As discussed by HECO T-13 (page 17) and summarized on HECO-1309 (page 2), HECO considers ELLIPSE a "core business software system" that must be upgraded periodically. In quantifying the amount of the upgrade costs included in the 2005 forecast, HECO assumed that the upgrade will be required every four years. Since the last upgrade occurred in 2003, the next upgrade was estimated to occur in 2007, two years after the 2005 test year. Nevertheless, HECO determined the non-labor cost of the last upgrade in 2003, escalated that cost to 2007 and then amortized the resulting upgrade costs over a four-year amortization period.

Although HECO T-13 (page 13) characterizes this upgrade as a "normalization" adjustment to the 2005 forecast test year, I disagree. While I do not disagree with the concept that software programs and systems must be upgraded on a periodic basis, the $161,000 of upgrade costs HECO has proposed to include in the test year forecast reflect an improper normalization adjustment. No upgrade fees will be incurred by HECO until the upgrade actually occurs – in 2007 by HECO's estimation. In quantifying overall revenue requirement based on a 2005 forecast test year, it is improper and inappropriate to inconsistently reach out to 2007 for certain cost of service elements and restrict other elements to 2005 average levels – after all, HECO will not record or incur any ELLIPSE upgrade costs in 2005.[20]

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20 See the direct testimony of Consumer Advocate witness Brosch (CA-T-1) for a discussion of the importance of the test year matching concept.

Q. DO YOU DISAGREE WITH HECO T-13 THAT THE COMPANY MAY FIND IT NECESSARY TO INCUR ELLIPSE UPGRADE COSTS IN 2007?

A. No. HECO's response to DOD/HECO-IR-6-19(h) indicates that Mincom (the vendor for ELLIPSE) currently plans to retire ELLIPSE version 5.2.3 used by the Company in 2007 and that plans to upgrade ELLIPSE in 2007 are in preliminary stages. However, the graphic appearing on page 3 of HECO's response to CA-IR-80 indicates a retirement date in June 2007, with reduced software support through 2009. Regardless of whether the upgrade occurs in 2007, 2008 or some other year, the documentation supplied by HECO clearly indicates that the upgrade will <u>not</u> occur in 2005. As such, HECO has produced no convincing support for or justification of the advance-collection of the future, post-test year costs.

Q. WITH REGARD TO THE ELLIPSE BUY-DOWN FEE AMORTIZATION, PLEASE EXPLAIN THE BASIS FOR HECO'S PROPOSED INCLUSION OF SUCH COSTS IN THE 2005 TEST YEAR FORECAST.

A. HECO T-16 (pages 14-15) explains that a mid-2004 amendment to the ELLIPSE software license agreement required two equal payments of $550,000 (June 2004 and January 2005) in exchange for reduced software maintenance fees. Because the reduced fees result in a pay-back period of about two years, HECO commenced amortization of the $1.1 million fee over the 24-month period, June 2004 through May 2006. Since twelve full months of this amortization is recorded in 2005, HECO included this amount in the forecast test year.

Q. WHY IS THE CONSUMER ADVOCATE PROPOSING TO EXCLUDE THESE COSTS FROM THE 2005 TEST YEAR?

A. Because the amortization will expire in May 2006, only five months of the amortization will remain subsequent to the test year. Assuming the rates resulting from the pending rate case are implemented near 2005 year-end, HECO will continue to collect the annual amortization in rates long beyond May 2006. As such, the ELLIPSE amortization does not represent a reasonable level of ongoing costs that HECO will record on a recurring basis.

VI. OFFICE LEASE COSTS.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-15?

A. In general, CA Adjustment C-15 (Exhibit CA-101) revises the original office lease forecast set forth on HECO-1605, recognizing certain updates and modifications to the lease terms, floor space or rental rates.

Q. COULD YOU GENERALLY DESCRIBE THE LEASE REVISIONS CAPTURED BY CA ADJUSTMENT C-15?

A. Yes. At the time HECO-1605 was originally prepared, various office leases were in the process of being renegotiated, in part because of contract terms calling for an assessment of lease market rates. HECO had also been exploring the possibility of leasing additional office space in Central Pacific Plaza and Pauahi Tower, near existing office space leased by the Company. CA Adjustment C-15 normalizes the effect of various lease changes identified in HECO's response to CA-IR-260 (revised 6/9/05) for purposes of quantifying the Consumer Advocate's revenue requirement recommendation.

Q. AS A RESULT OF THIS ADJUSTMENT, IS THE CONSUMER ADVOCATE IN AGREEMENT WITH HECO AS TO THE AMOUNT OF OFFICE RENT EXPENSE THAT IS PROPERLY INCLUDED IN THE OVERALL REVENUE REQUIREMENT FOR THE 2005 FORECAST TEST YEAR?

A. No. In the Company's original filing, HECO forecasted $807,294[21] for the rent and related taxes on 58,313 square feet of office space located at 233 South King Street, Honolulu, Hawaii (aka the "King Street building"), which HECO has leased for many years from the Estate of Bernice Pauahi Bishop. HECO subsequently negotiated new office lease terms that materially increase the cost of the King Street building that the Company now seeks to include in utility rates. Although there remains some uncertainty regarding the exact amount HECO proposes to include in overall revenue requirement, I disagree

21 The $807,294 is before allocation of $301,365 of rent to HEI.

with the Company's general proposition to recognize this lease transaction as a "capital lease" for ratemaking purposes.

Q. PLEASE SUMMARIZE THE BASIS FOR THE CONSUMER ADVOCATE'S DISAGREEMENT WITH THE CAPITAL LEASE TREATMENT OF THE KING STREET BUILDING LEASE.

A. There are several reasons that the Consumer Advocate objects to HECO's proposed capital lease treatment for ratemaking purposes, including:

- The capital lease treatment recommended by HECO significantly increases ratepayer costs, as compared to operating lease treatment, by including: a capital lease asset in rate base, a capital obligation in the capital structure as well as an asset amortization and imputed interest in quantifying operating income.
- HECO proposes to include the capital lease asset in rate base, pursuant to FAS13,[22] even though HECO does not and will not have any ownership interest in the lease facilities.
- HECO also proposes to include the capital lease obligation in the capital structure, even though the Company has not borrowed

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22 Financial Accounting Standards Board's Statement of Financial Accounting Standard No. 13, "Accounting for Leases."

any funds, nor issued any evidence of indebtedness related to the capital lease.

Consequently, the Consumer Advocate recommends that the King Street lease be recognized for ratemaking purposes on terms no less disadvantageous to ratepayers than if the new lease agreement qualified as an operating lease under FAS13.

Q. PLEASE EXPLAIN WHY THE CAPITAL LEASE TREATMENT SIGNIFICANTLY INCREASES RATEPAYER COSTS.

A. Under an operating lease arrangement, the expense recorded by the Company would be equal to the amount of the lease payments, plus applicable taxes, before allocation to HEI. Because HECO has concluded that the King Street lease qualifies for capital lease treatment for financial accounting purposes, the Company has proposed to include a $10,112,734 capital lease asset in rate base, a $10,112,734 capital lease obligation in the capital structure at a 5.75% cost rate and a capital lease amortization of $192,685 in operating expense.[23] Under an operating lease, there is no asset or "investment" to include in rate base on which the utility can seek to recover a current return on "investment."

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23 HECO responses to CA-IR-260 (revised 6/9/05) and CA-IR-688 (revised 6/10/05).

Even though the Company has determined that the new King Street lease qualifies for capital lease treatment under FAS13, HECO's investors have not advanced any funds to support an asset purchase or rate base addition. In reality, HECO neither invested nor borrowed $10 million as a result of the King Street lease negotiations. Nevertheless, it is the inclusion of that $10 million asset in rate base that is the primary driver in the difference in overall revenue requirement between the capital lease and the operating lease treatments.

Q. DID HECO FILE A PETITION WITH THE COMMISSION SEEKING AN ORDER REGARDING THIS CAPITAL LEASE OBLIGATION?

A. Yes. On April 6, 2005, HECO filed a "Petition and Certificate of Service" (hereinafter, the "Petition"), designated as Docket No. 05-0084, which generally sought a declaratory ruling from the Commission indicating that the long-term obligation, to be recorded pursuant to FAS13, will not require approval under Hawaii Revised Statutes ("HRS") § 269-17. Should the Commission determine that HRS § 269-17 does apply, HECO alternatively sought Commission approval of the capital lease agreement.[24]

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[24] On May 5, 2005, the Consumer Advocate filed its statement of position in Docket No. 05-0084, indicating: HRS § 269-17 does not apply to the King Street lease; the Consumer Advocate has not determined whether the King Street lease is reasonable; and all ratemaking issues relating to this lease should be addressed in HECO's pending rate case. On May 13, 2005, the Commission issued Decision and Order No. 21821 concluding, at page 13, that HRS § 269-17 does not apply to the King Street lease and that all ratemaking issues will be addressed in the pending rate case.

Q. EARLIER, YOU EXPRESSED SOME UNCERTAINTY REGARDING THE EXACT AMOUNT BY WHICH HECO'S PROPOSED CAPITAL LEASE TREATMENT WOULD INCREASE OVERALL REVENUE REQUIREMENT. PLEASE EXPLAIN THE NATURE OF THAT UNCERTAINTY.

A. HECO's original filing[25] proposed to include $807,294 of lease expense for the King Street building, before allocation of any rent to HEI. According to a parenthetical comment disclosed in Note (6) to HECO-1605, this lease cost included $775,000 of rent (plus taxes) "based on the terms of the 'Offer of New Lease' dated 11/20/03." In the original response to CA-IR-260,[26] HECO first summarized its proposed ratemaking treatment of the King Street lease as including $521,315 in amortization expense (before considering the HEI rent credit), $9.948 million in rate base and $10.115 million lease obligation. In the original response to CA-IR-615,[27] HECO provided a series of calculations (pages 5-12) supporting annual revenue requirements under two versions or scenarios of capital lease treatments.

Under rate base/rate of return regulation, the highest revenue requirement associated with a fixed asset occurs in the first year, because of the phenomenon of declining rate base. HECO's response to CA-IR-615 was

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25 See HECO-1605.

26 CA-IR-260 was submitted by the Consumer Advocate on February 10, 2005. HECO provided its original response on or about April 15, 2005.

27 CA-IR-615 was submitted by the Consumer Advocate on March 29, 2005. HECO provided its original response on or about May 9, 2005.

no different. Under the scenario "Capital Lease for Book and Ratemaking," HECO estimated the first year revenue requirement at $1.993 million, including net a positive net income of $649,000, representing an after tax equity return on the "investment" in rate base. The other scenario, "Capital Lease With Recovery based on Lease Payments," resulted in a slightly lower overall revenue requirement of $1.643 million, including after tax net income of $655,000.

Unfortunately for ratepayers, it appears that both "capital lease" revenue requirement calculations recognize an offset, or credit, for HEI rent payments. As a result, the $1.993 million and $1.643 million amounts appear more comparable to the much lower operating lease cost of $505,926 (net of HEI rent credit) set forth on the original HECO-1605, not the higher gross amount of $807,294. Using these numbers, Commission adoption of HECO's proposed ratemaking treatment of the capital lease, negotiated by the Company, would effectively require ratepayers to bear $1.5 million to $1.1 million in additional lease costs – attributable solely to the first year of the King Street capital lease.

On June 13, 2005, HECO revised the revenue requirement calculations previously supplied in response to CA-IR-615, in part changing the assumed rate of interest rate on the lease obligation included in the capital structure. However, this revision had a relatively immaterial impact on the first year revenue requirement and net income amounts from the original response to CA-IR-615.

Adding to the Consumer Advocate's uncertainty as to which number truly reflects the presumed lease obligation due to the numerous revisions, HECO also revised its response to CA-IR-260 on June 9, 2005, stating that it intended to revise its lease amortization expense downward from $521,315 to $192,685. Since the 6/13/05 "revised" response to CA-IR-615 included an amortization of $525,789 but was provided after the 6/9/05 "revised" response to CA-IR-260 cited to the lower $192,685 amount, there is further uncertainty as to which of these moving parts HECO intends to "fix" for ratemaking purposes.

Q. WHY DOES THE OPERATING LEASE TREATMENT YIELD A MUCH LOWER REVENUE REQUIREMENT IN THE FIRST YEAR, AS COMPARED TO EITHER CAPITAL LEASE SCENARIO?

A. Rent costs, under an operating lease, are basically recovered dollar for dollar through revenue requirement, much like payroll or outside service expense. However, HECO's "capital lease" treatment results in a significant non-cash addition to rate base that is amortized over the approximate 20-year term of the new King Street lease. The rate base inclusion of the FAS13 capital lease asset significantly increases overall revenue requirement.

Q. PREVIOUSLY YOU STATED THAT, UNDER RATE BASE/RATE OF RETURN REGULATION, REVENUE REQUIREMENT IS THE HIGHEST IN THE EARLY YEARS OF A FIXED ASSET'S SERVICE LIFE BECAUSE OF DECLINING RATE BASE. YOU THEN COMPARED THE FIRST YEAR REVENUE REQUIREMENT UNDER TWO CAPITAL LEASE SCENARIOS HECO PROVIDED IN RESPONSE TO CA-IR-615. IS IT POSSIBLE FOR HECO'S CAPITAL LEASE APPROACH TO RECOGNIZE A SUFFICIENTLY LOWER RATE BASE IN THE LATER YEARS SUCH THAT THE CAPITAL LEASE REVENUE REQUIREMENT APPROACH COULD BE CHEAPER FOR RATEPAYERS, ON A CUMULATIVE BASIS, THAN THE OPERATING LEASE?

A. No, not under any of the revenue requirement models HECO has thus far produced in response to CA-IR-615. In fact, it would be improbable for such a feat to be accomplished by any model that included a rate base component, absent artificially reducing the amortization amount for the express purpose of achieving a result equal to or less than the operating lease treatment. The following table summarizes the 2005 and 20-year cumulative revenue requirement and net income amounts for both capital lease scenarios from the June 13, 2005, response to CA-IR-615:

	2005		20-Year Cumulative	
	Revenue Requirement	Net Income	Revenue Requirement	Net Income
Capital Lease for Book and Ratemaking	$1,993,000	$649,000	$25,558,000	$7,1426,000
Capital Lease with Recovery based on Lease Payments	1,643,000	655,000	28,115,000	8,224,000

Source: HECO response to CA-IR-615 (revised 6/13/05).

In comparison, HECO-1605 (both original and revised) indicates that the annual King Street lease payments are $775,000 (plus $32,294 of related taxes). The lease agreement calls for that payment to remain fixed through November 2009, with 10% increases effective December 1 of 2009 ($852,500), 2014 ($937,750) and 2019 ($1,031,525).[28] Assuming each lease step remains effective for the specified five-year period and the Hawaii general excise tax remains fixed at 4.166%, the cumulative revenue requirement of the 20-year lease payments would be $18.733 million[29] -- before any reduction or offset to recognize the HEI rent allocation. Even assuming no HEI rent credit, the operating lease treatment is significantly less than the capital lease scenarios offered by HECO.

28 HECO's response to CA-IR-615 (Revised 6/13/05).

29 $775,000 times 5 years plus $852,500 times 5 years plus $937,750 times 5 years plus $1,031,525 times 5 years equals $17,983,875 in lease payments times 1.04166 GET factor is $18,733,083.

Q. ISN'T A DECLINING NET INVESTMENT CONSISTENT WITH RATE BASE TREATMENT OF DEPRECIABLE PLANT OWNED BY A UTILITY?

A. Yes, that is true. It is also true that the utility and its ratepayers would have some interest in the terminal value of any utility-owned property upon disposition, sale or abandonment of that property. However, under a capital lease, the interest in the terminal value of the property resides with the owner, or the Estate of Bernice Pauahi Bishop with respect to the King Street building. HECO's proposed capital lease treatment, as currently understood by the Consumer Advocate, would improperly burden and significantly overcharge ratepayers with the added cost of theoretical ownership without the related benefits.

Q. YOU ALSO STATED THAT HECO DOES NOT, AND WILL NOT HAVE ANY OWNERSHIP INTEREST IN THE LEASED KING STREET BUILDING, EVEN UNDER THE NEW LEASE AGREEMENT. HOW LONG HAS HECO LEASED THE KING STREET BUILDING FROM THE ESTATE OF BERNICE PAUAHI BISHOP?

A. According to HECO's "Petition" (Docket No. 05-0084), HECO has occupied the King Street building since 1927. The new 20-year agreement enables HECO to continue to lease the King Street building and provide service to customers without interruption.[30] At the expiration of the new lease term, HECO will have occupied the King Street building for almost 100 years without any ownership interest in the land or the building. The new lease agreement does nothing to change that situation.

Q. AT PAGES 7 THROUGH 10 OF HECO'S PETITION IN DOCKET NO. 05-0084, HECO INDICATES THAT THE COMPANY IS REQUIRED TO ACCOUNT FOR THE NEW KING STREET LEASE AS A CAPITAL LEASE BECAUSE "CRITERIA D" OF FAS13 IS MET. COULD YOU BRIEFLY DESCRIBE "CRITERIA D" AND EXPLAIN WHY THE CAPITAL VERSUS OPERATING LEASE TREATMENT IS IMPORTANT FOR RATEMAKING PURPOSES?

A. The referenced portion of HECO's Petition (Docket No. 05-0084) provides a detailed discussion of the various "criteria" specified in FAS13 to determine whether a long-term lease should be reported as an operating lease or a capital lease for financial reporting purposes. At page 9 of the Petition, HECO stated that the present value of the minimum lease payments was approximately 100% of the fair value of the lease property, causing the King Street lease to satisfy "Criteria d" and requiring capital lease disclosure.[31]

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30 HECO Petition and Certificate of Service, Docket No. 05-0084, page 5.

31 Criteria d: If the present value of the minimum lease payments equals or exceeds 90% of the fair value of the lease property to the lessor (i.e., net of any related investment tax credit), the lease shall be classified as a capital lease.

Typically, the amounts paid to rent or lease office space are recorded as an operating expense. For a regulated utility, those lease costs may be included in the overall revenue requirement, absent evidence that the costs were either unnecessary or unreasonable. Whether financial accounting (i.e., FAS13) requires a lease to be recognized as a capital lease becomes critical for ratemaking purposes if two general conditions apply:

1. Capital lease treatment causes overall revenue requirement to be higher than operating lease treatment; and
2. The regulated utility seeks to set regulated rates to recover the higher cost of the capital lease.

In the May 5 Letter identified previously, HECO stated its intent to update rent expense as discussed in its response to CA-IR-260, which revised HECO-1605 to reflect added lease space and revised rental rates. The response to CA-IR-260 updated HECO-1605 and stated that the ratemaking treatment of the new King Street lease was consistent with the capital lease accounting determination. Although HECO did not present this issue in its direct testimony, the Consumer Advocate expects HECO to raise the capital lease issue in its rebuttal filing. Given the subsequent information that has been provided and the related petition filed in Docket No. 05-0064, the Consumer Advocate must address its opposition to the added cost of the proposed capital lease treatment at this time.

VII. REMOVE DEMAND SIDE MANAGEMENT ("DSM") PROGRAM COSTS.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-17.

A. On March 16, 2005, the Commission issued Decision and Order No. 21698, separating HECO's DSM and load management costs from the pending rate case and opening Docket No. 05-0069 to consider those issues. CA Adjustment C-17 (Exhibit CA-101) adjusts the Company's 2005 forecast to remove all DSM program related costs, except for limited administrative costs, and incremental integrated resource planning ("IRP") costs from the determination of base rates.

Q. HOW WAS CA ADJUSTMENT C-17 DETERMINED?

A. In a May 5, 2005 letter to the Consumer Advocate and the Department of Defense, HECO described and quantified a series of proposed updates and revisions to its filing, including an adjustment removing DSM and load management costs from the Company's 2005 test year. CA Adjustment C-17 recognizes and adopts that proposed adjustment, but removes the $833,813 HECO proposes to recover in base rates. In addition, CA Adjustment C-17 removes $618,000 of "normalized" incremental IRP costs identified on HECO-1027 through HECO-1029.

Q. HAS HECO SUBSEQUENTLY EXPRESSED THE INTENT TO FURTHER REVISE THE AMOUNT OF DSM RELATED COSTS IT DESIRES TO INCLUDE IN BASE RATES?

A. Yes. In response to CA-IR-446 and CA-IR-533 provided to the Consumer Advocate on June 9, 2005, HECO again revised its proposed May 5th DSM adjustment to recognize additional general and corporate advertising costs for inclusion in the amount of DSM it seeks to include in base rates – in spite of the establishment of Docket No. 05-0069 on March 16, 2005 to evaluate such program costs. The Consumer Advocate also recommends rejection of this latest revision and suggests that any recovery of these additional costs be taken up in Docket No. 05-0069.

Q. WHEN WERE CA-IR-446 AND CA-IR-553 SUBMITTED TO HECO?

A. These interrogatories were issued by the Consumer Advocate shortly after Docket No. 05-0069 was opened: CA-IR-446 on March 18, 2005, and CA-IR-533 on March 29, 2005. The Consumer Advocate has diligently conducted its review of the Company's rate filing and submitted discovery throughout this engagement. Unfortunately, HECO chose to revise the amount of DSM to be included in base rates and communicated the revision to the parties on May 5, 2005, through responses to these interrogatories that had been outstanding for 84 days and 73 days, respectively. While the Consumer Advocate certainly understands the need to reconsider and reevaluate issue quantifications and approaches over time, the belated and material change presented by HECO in the responses to CA-IR-446 and CA-IR-533 are ill timed and not appropriate for consideration in setting base rates. Moreover, the specific DSM-related activities and cost levels properly recoverable through either base rates or the DSM rate rider are more appropriately evaluated in the context of the separate Docket opened by the Commission for the specific purpose of undertaking such evaluations.

Q. WHY SHOULD HECO'S REVISIONS TO THE AMOUNT OF DSM AND LOAD MANAGEMENT COSTS INCLUDED IN BASE RATES, AS IDENTIFIED IN THE RESPONSES TO CA-IR-446 AND CA-IR-533, NOT BE ADOPTED BY THE COMMISSION?

A. As indicated by these responses, the increased costs are largely associated with HECO's plans to undertake an aggressive marketing effort, focusing on DSM and customer awareness of energy options and conservation. The Commission recently considered and rejected a more aggressive energy awareness pilot program in Decision and Order No. 21756 (Docket No. 03-0142), dated April 20, 2005. If allowed in base rates, the reasonableness of the proposed costs and planned efforts would be inappropriately injected into the current rate case proceeding – at the last minute. HECO could have and should have notified the parties and the Commission of its intent to seek base rate recovery of these costs long ago.

Because of the limited resources and largely expired discovery opportunity available that can be dedicated to the review and evaluation of HECO's proposed and expanded DSM activities, the Consumer Advocate shifted its DSM efforts away from the pending rate case for dedication in newly established Docket No. 05-0069 – the proper forum for taking up HECO's DSM program plans and cost recovery issues. Since the aggressive advertising plans were recently rejected by the Commission, the Consumer Advocate contends that this belated attempt to introduce these issues into the rate case with little notice is particularly disadvantageous, since both the Consumer Advocate and Department of Defense ("DOD") are now attempting to deal with HECO's protracted delays in responding to discovery, while assembling their respective testimonies and exhibits scheduled for filing on June 28, 2005, and July 8, 2005. The schedule simply allows inadequate time for the Consumer Advocate's DSM consultants to undertake additional discovery or further evaluate the propriety of these costs.

Q. IS IT THE PURPOSE OF YOUR TESTIMONY ON THIS SUBJECT TO EVALUATE HECO'S PLANNED EXPANSION OF ITS DSM/ IRP PROGRAM OFFERINGS OR TO ASSESS THE FEASIBILITY OF THE COMPANY'S PLANS TO AGGRESSIVELY CONVEY THE CONSERVATION MESSAGE TO CUSTOMERS?

A. No. Utilitech was not retained to undertake this work on behalf of the Consumer Advocate. Upon the establishment of Docket No. 05-0069 and receipt of HECO's May 5, 2005 forecast revision letter, the Consumer Advocate and its DSM consultant (La Capra Associates) reasonably expected that all DSM related costs, in excess of $685,000 of IRP Administrative Costs[32] includable in base rates, would be fully addressed in that new docket. Consequently, the purpose of my testimony is to convey the Consumer Advocate's concurrence with the base rate inclusion of the $685,000 and intent to address all DSM related issues in Docket No. 05-0069.

Q. WHAT SHOULD BE DONE PROSPECTIVELY TO ACCOUNT FOR THE DSM/IRP COSTS INCLUDED IN THE RATE CASE REVENUE REQUIREMENT?

A. The Commission should be aware of the dollar amount of the costs allowed in base rates, i.e., the $685,000 described above. All issues associated with the

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32 The components of the $685,000 of IRP planning costs included in base rates are listed on CA Adjustment C-17 (Exhibit CA-101).

approval of specific DSM programs and the manner of cost recovery should be taken up in Docket No. 05-0069.

VIII. RATE CASE EXPENSE.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-18.

A. CA Adjustment C-18 (Exhibit CA-101) represents the Consumer Advocate's recommendation that HECO's forecast rate case expense be reduced to exclude the cost of its DSM consultants and to amortize the remaining amount over a four-year period.

Q. DID HECO'S TEST YEAR FORECAST HAVE THE EFFECT OF AMORTIZING RATE CASE EXPENSE?

A. Yes. In direct testimony, Company witness Sekimura (HECO T-16, pages 2-3 and HECO-1603) proposed to amortize $284,000 of rate case expense over a three-year period, resulting in an annual amortization of $95,000. The original estimate included costs for outside counsel, rate design and rate of return consultants and miscellaneous costs associated with this proceeding. In response to CA-IR-258, HECO significantly increased its cost estimate to $672,000, causing the three-year annual amortization to increase from $95,000 to $224,000.

Q. HOW DOES HECO'S REVISED FORECAST ESTIMATE COMPARE WITH ITS ORIGINAL ESTIMATE?

A. HECO has more than doubled its original estimate of rate case expense, particularly with a substantial increase in legal fees and the addition of DSM consulting fees, as shown in the following table.

		Original Forecast	Revised Forecast
Legal Fees		$205,000	$377,000
Consultant - Rate Design		30,000	
Consultant - Return on Equity		30,000	59,000
Consultant - Rate of Return on Rate Base			40,000
Consultant – DSM			157,000
Stenographer		10,000	10,000
Consultant - HEI impact (affidavit)		8,000	16,000
Supplies		1,000	3,000
Printing Services			10,000
Total 2005 Rate Case Expenses		$284,000	$672,000
Amortization Period	3 years		
2005 Test Year Amortization		$94,667	$224,000
		(a)	(b)

Footnotes:

(a) Source: HECO-1603, as filed.

(b) Source: HECO response to CA-IR-258.

Q. IF HECO'S FORECAST INCLUDES THE AMORTIZATION OF RATE CASE EXPENSE, WHY IS CA ADJUSTMENT C-18 NECESSARY?

A. CA Adjustment C-18 is necessary for several reasons. First, in preparing its original test year forecast, HECO estimated total rate case expense of

$284,000. While this amount included out-of-pocket, non-employee labor costs and legal/ consulting fees, it did not include the cost of the consultants retained by HECO to present its DSM proposals. In addition to adding $157,000 for the DSM consultants, HECO also increased its estimated legal fees by $172,000 to $377,000. However, the Consumer Advocate disagrees with the proposed recovery of the DSM related costs as rate case expense in the current proceeding. Instead, the $157,000 for the DSM consultants and any added legal fees associated with DSM should be subject to cost recovery in Docket No. 05-0069. Because the Commission removed DSM-related issues from consideration in the pending rate case, the recovery of any costs incurred by HECO to develop and present those issues should also be taken up in that Docket. In rebuttal testimony, HECO should disclose the amount of legal fees included in the revised $377,000 estimate that will support the Company's efforts in Docket No. 05-0069.

Second, given the magnitude of the revised rate case estimate (i.e., $672,000 vs. $284,000), the three-year amortization period creates an increased over-collection risk to customers, if the time lag to process the next HECO rate case exceeds three years. The objective for recognizing the amortization of rate case expense in cost of service is to provide a ratable mechanism for recovery of the costs reasonably incurred by the utility to pursue an increase in rates. That objective is neither to deny recovery nor provide for an over-recovery of those costs. By extending the amortization period, as proposed by the Consumer Advocate, a significant amount of rate case expense is recovered through rates on an annual basis, while reducing the potential over-recovery if the next rate case proceeds on an extended timeline, similar to the lengthy delay since HECO's last rate case.

Q. WHAT IS THE BASIS FOR HECO'S PROPOSED THREE-YEAR AMORTIZATION OF RATE CASE EXPENSE?

A. In quantifying the amount of rate case expense to include in the test year forecast, Company witness Sekimura (HECO T-16, pp. 2-3) proposed a three-year amortization period, citing to Commission Decision and Order No. 12679 (East Honolulu Community Services, Inc., Docket No. 7064).[33] However, the issue in that proceeding did not involve the selection of the amortization period, as the parties were in agreement regarding use of a three-year period. Instead, the issue focused on the <u>amount</u> of rate case expense to be amortized.

In the context of issues involving the length of the amortization period, Commission Decision and Order No. 11317 (Docket No. 6531) denied HECO's proposal to recover in-house labor and labor-related costs as rate case expense and adopted the Consumer Advocate's three-year amortization

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33 Exhibit HECO-1606 contains a copy of a portion of D&O 12679 addressing rate case expense.

period, rather than HECO's recommended two-year period, as addressed in the following excerpt:

> ...The Consumer Advocate's selection of a three-year amortization period is based on the average number of years intervening between cases in HECO's last three rate cases, including this docket. HECO contends that a two-year amortization period is more appropriate. It represents that, in its next rate case, the company will be utilizing 1992 as a test year. [footnote omitted]
>
> In the majority of rate cases before this commission, we accepted a three-year amortization period for regulatory commission expense. For instance, we applied a three-year amortization period in the recent HELCO rate case (Docket No. 6432). We will also apply it in this docket. The periods between rate cases vary in length. We will continue to adhere to a three-year amortization period, unless a pattern of rate filings in the future suggests otherwise.
>
> [Decision and Order No. 11317 (Docket No. 6531), p. 97]

I would also note that in HECO's 1994 test year rate case, Docket No. 7700, I sponsored testimony on behalf of the Consumer Advocate removing HECO's proposed rescheduling of the unamortized amortizations of the two previous rate cases (Docket Nos. 6531 and 6998) and shortening the Company's proposed three-year amortization of the 1994 rate case to two years.

Q. IN DOCKET NO. 7700, WHAT WAS THE BASIS FOR YOUR RECOMMENDATION THAT A TWO-YEAR AMORTIZATION PERIOD SHOULD BE USED, INSTEAD OF HECO'S THREE-YEAR PERIOD?

A. At that time, HECO's three most recent rate proceeding[34] had been filed generally following a two-year pattern. In addition, HECO had indicated plans to immediately file a follow-up rate case, which the Consumer Advocate considered to be an abnormal event that was not indicative of series of annual rate filings.[35] So, a two-year amortization was proposed. While the amortization issue was resolved by agreement among the parties in Docket No. 7700, Decision and Order No. 13704 described that resolution, as follows:

> ... Included in regulatory commission expense is the cost of this rate case proceeding. Rate case costs are normally amortized over a period that represents the typical interval between rate cases. In prior rate cases the commission amortized the rate case costs over a three-year period, since HECO was typically filing rate cases every three years. However, in this rate proceeding, the parties agreed not to amortize the rate case cost and to allow HECO to recover the cost within one year. We will allow HECO to recover the cost of this rate proceeding over the period of a year since HECO has already filed an application for another rate increase in Docket No. 7766, with a 1995 test year. In light of that filing, unless we allow HECO to include the full rate case cost, HECO will not have the opportunity to recover all of its costs incurred in this proceeding.
> [Decision and Order No. 13704, p. 39]

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34 Docket Nos. 6531, 6998 and 7700.

35 Docket No. 7700, Direct Testimony of Steven C. Carver (CA-T-5), pages 56-57.

Q. WHAT ARE HECO'S PLANS FOR A "NEXT" RATE CASE?

A. HECO is unsure when it will file its "next" rate case, as indicated by the following response to CA-IR-259:

> HECO has not determined when HECO would file its next rate increase application. HECO does not expect to file as frequently as in the early 1990's (1990, 1992, 1994 and 1995 test year cases filed within 6 years) or as infrequently as in the late 1990's and early 2000's (one case in 10 years). The decision on its next rate increase application will depend on a number of factors, including the amount of rate relief granted in this proceeding, the impact and results of the Energy Efficiency Docket proceeding (Docket No. 05-0069) and the mechanism used to recover program-related costs, the completion of significant capital expenditures and computer software development projects, increase in operations and maintenance expenses beyond the normalized amounts included in rates as a result of this rate case, and changes in kilowatthour sales and the cost of capital for the Company. HECO has utilized a three-year amortization period, since based on the current planned investments, and proposed treatment of lost margins for DSM programs, it is not unlikely that HECO's next rate case would be filed within three years from the conclusion of this proceeding.
> [HECO response to CA-IR-259]

In spite of this uncertainty, a three-year amortization period is too short given the magnitude of the overall cost estimate. According to HECO's last IRP, HECO's next capacity addition is not scheduled for completion and operation until 2009. Assuming that Docket No. 05-0069 is resolved in a manner that provides for recovery of any DSM and IRP program costs ultimately approved by the Commission, in excess of the amount included in base rates in the pending proceeding, the Energy Efficiency Docket should not cause HECO to file its "next" rate case on an expedited basis. In balance, a four-year amortization period appears reasonable and should be accepted by the Commission.

Although the DSM issues will be addressed by the Commission in a separate docket, HECO T-10 (pages 54-55) describes the Company's recommendation to annualize the shortfall in fixed cost contribution associated with revenue lost from the implementation DSM programs over three program years. Interestingly, HECO T-10 recommended three years as "approximately equal to the average interval between rate cases, based upon the last four rate cases and the current rate proceeding, as shown in HECO-1020." Referring to HECO-1020, the average rate case interval is calculated at 3.8 years, which reasonably approximates the Consumer Advocate's recommended four-year amortization period for rate case expense.

Q. WHY HAVE YOU PROPOSED TO EXCLUDE THE CONSULTING FEES AND LEGAL FEES ASSOCIATED WITH HECO'S DSM RECOMMENDATIONS FROM THE LEVEL OF RATE CASE EXPENSE TO BE AMORTIZED AND INCLUDED IN BASE RATES?

A. As previously stated, the Commission recently established Docket No. 05-0069 to separately address HECO's proposed DSM program plans and related cost recovery issues. CA Adjustment C-17 only allows the Company to include estimated DSM/ IRP administrative costs in base rates, as discussed in a separate testimony section. Rather than allow recovery of

DSM-related consultant and legal costs associated with processing Docket No. 05-0069 in base rates, CA Adjustment C-18 removes such costs so that recovery of the DSM consulting witness fees plus the related legal fees can be considered by the Commission and recovered through any mechanism the Commission deems appropriate, obviating the need to provide for the recovery of such costs in the current "rate case" docket.

In addition, this approach allows a better matching of the recovery of the costs of participating in Docket No. 05-0069 with the program costs that might ultimately be approved in that proceeding. In the event that Docket No. 05-0069 follows a procedural track significantly different from the current rate case, the Consumer Advocate's recommendation will eliminate any need for the Commission to reconcile costs from Docket No. 05-0069 with the "rate case" expenses allowed in base rates – thereby streamlining the administrative process and minimizing overlap between the proceedings.

Q. IS IT POSSIBLE THAT HECO COULD FILE ITS "NEXT" RATE CASE BEFORE THE EXPIRATION OF THE CONSUMER ADVOCATE'S FOUR-YEAR AMORTIZATION PERIOD?

A. Yes. It is possible that HECO could file its next rate case as early as 2006 or not until 2010. The timing of HECO's next filing is impossible to precisely estimate or know with certainty. However, $672,000 is a significant sum to process a rate case. While the Consumer Advocate has not challenged that cost estimate, the use of a four-year amortization helps mitigate the customer impact and should be adopted by the Commission.

In the event that HECO does file its next rate case in two or three years, the selection of a four-year amortization period could arguably result in a portion of the rate case costs not being recovered from ratepayers, thereby providing an incentive for the Company to closely scrutinize the level of costs it chooses to incur in future proceedings.

Q. SINCE THE CONSUMER ADVOCATE IS NOT CONTESTING HECO'S CURRENT RATE CASE COST ESTIMATE, DO YOU HAVE ANY ADDITIONAL RECOMMENDATIONS THAT THE COMMISSION SHOULD CONSIDER?

A. Yes. Prior to the commencement of any formal hearings scheduled in this proceeding, I recommend that HECO provide the actual amount of rate case expense incurred to-date and provide an estimate of the remaining cost to complete – specifically identifying any consulting or legal fees associated with DSM-related issues. Although I am not recommending any update of rate case expense to actual incurred costs, I do believe that the Company should be expected to demonstrate that it has incurred or is highly likely to incur at least $672,000, less DSM costs, to process this rate case. If the actual charges are expected to be materially less than HECO's estimate, then the amortizable amount should be reduced accordingly.

Finally, CA Adjustment C-18 limits the amount of legal fees to the Company's original forecast estimate. This amount is a placeholder, pending receipt and review of the rebuttal information cited previously.

IX. PAYROLL EXPENSE.

Q. PLEASE DESCRIBE CA ADJUSTMENTS C-20 AND C-21.

A. CA Adjustments C-20 and C-21 (Exhibit CA-101) revise the Company's salary and wage expense forecast to modify the standard labor rates originally proposed by HECO and to recognize average non-production employee counts for the 2005 forecast period.

A. STANDARD LABOR RATES & OVERTIME PAY.

Q. HOW WAS CA ADJUSTMENT C-20 QUANTIFIED?

A. During the review of HECO's 2005 test year forecast workpapers, the Consumer Advocate determined that the method HECO used to forecast the 2005 standard labor rates may have the effect of overweighting overtime pay. As a result of a series of discussions with HECO, the Company analyzed the calculations of the standard labor rates and quantified an incremental adjustment to revise the standard labor rates underlying the 2005 forecast test year.

Q. PLEASE EXPLAIN THE CONCEPT UNDERLYING HECO'S USE OF "STANDARD LABOR RATES."

A. HECO T-13, pages 13-15, provides a somewhat lengthy explanation of the Company's need for, and reliance on standard labor rates. In general terms, HECO's core business software system (ELLIPSE) applies standard labor rates to productive labor hours for purposes of distributing labor costs between the various expense and capital accounts. In developing the standard labor rates, HECO divides actual productive pay (e.g., straight time, overtime, etc.) by actual productive hours, by identified labor classes. This process of quantifying standard labor rates results in periodic true-ups, with correcting entries, at least once a year as needed.

In preparing the 2005 test year forecast, HECO started with 2003 recorded data (i.e., actual productive labor dollars and hours) as the base year. The 2003 standard labor rates were then adjusted to reflect wage increases granted or to be granted in 2004 and 2005.[36]

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36 The Company's calculation of the standard labor rates used in the 2005 test year forecast was provided in HECO's response to CA-IR-249.

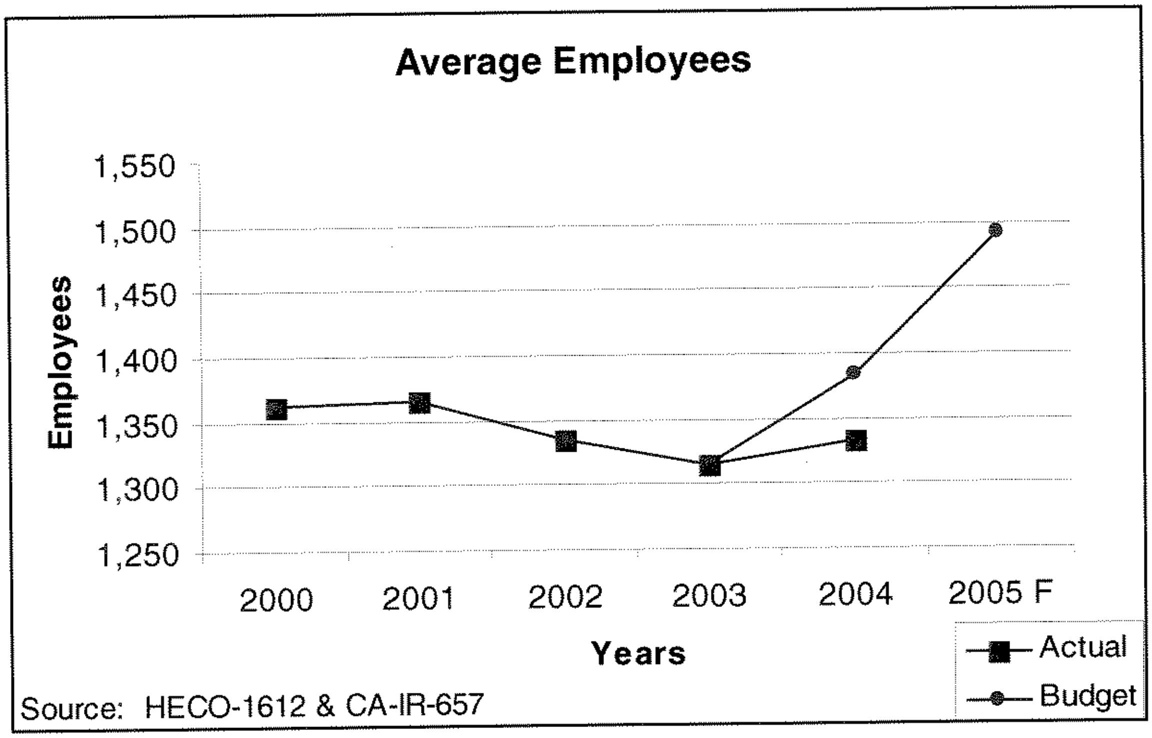
Q. WHY DOES CA ADJUSTMENT C-20 REVISE HECO'S FORECAST STANDARD LABOR RATES?

A. As discussed by HECO T-1 (pages 18-19), the "events of September 11" created substantial uncertainty and led HECO to undertake various measures to manage its financial and business affairs:

> In 2001, prior to the events of September 11, HECO's financial projections for 2002 and 2003 indicated that earnings would be below the last allowed return. The events of September 11, 2001, created substantial economic uncertainty for our nation, our state and HECO in the immediate future at that time. Kilowatthour sales dropped 3% after the terrorist attacks, and the impact of the fall in the stock market on HECO's pension plans was very dramatic. At that point, HECO appeared to be in a dire situation and was looking at the potential for furloughs, layoffs of a substantial number of employees, and significant benefit cuts and eliminations. Before taking such drastic measures, HECO implemented staff caps, and staffing levels were carefully monitored. Vacancies were not automatically filled. Each position had to be justified in light of current circumstances and, whenever the opportunity presented itself, HECO managed with less than was necessary in the long term. HECO, as well as the rest of the economy, had to weather the economic turmoil of the terrorist attacks. Filing a rate increase application at such a time would have significantly impacted the already soft economy. HECO deliberately reduced spending, while not compromising reliability, during that period. However, such reduction in the level of spending and unfilled positions can not continue for an indefinite period of time. After a while, the vacancies need to be filled or certain work will not get done. HECO is slowly getting back to an optimal staffing level. As many of the witnesses discuss in their testimonies, often the test year levels may be higher than the recent historic levels, largely because of the financial constraints imposed after the events of September 11.
> [HECO T-1, pages 18-19]

Using average employee count data primarily from HECO-1612, the following chart shows the drop-off in average employee levels in 2002 and

2003, with the recovery budgeted for 2004 and explosive increase forecast for the 2005 test year.



While managing reductions in spending and employee levels without compromising reliability, the Company would have been unable to schedule the "vacant" or "unfilled" employee positions to undertake any of the work requiring attention in calendar 2003 – the base year for HECO's standard labor rate forecast. In the context of the dramatic increase in average employee levels between 2003 (1,315) and HECO's 2005 test year forecast (1,493), the Consumer Advocate was concerned that the Company may have found it necessary to schedule its workforce for disproportionate levels of overtime in 2003, in relation to the overtime required with a more robust workforce in 2005, or to engage outside contractors beyond normal needs. In order to evaluate whether a disproportionate "mix" of productive overtime and productive regular time may have existed in the 2003 base year in relation to the 2005 forecast test year, the Consumer Advocate issued a series of information requests seeking additional data.[37]

Q. WHAT IS THE CURRENT STATUS OF THE CONSUMER ADVOCATE'S EFFORTS TO REVIEW THIS MATTER?

A. Following several conference calls and the exchange of additional documentation, HECO's May 5 Update Letter referred to the ongoing dialogue with the Consumer Advocate in the following excerpt:

> In addition, as noted in response to CA-IR-76, HECO is in discussion with Mr. Carver of Utilitech (the Consumer Advocate's consultant) to review the standard labor rates used for the test year, and the level of overtime dollars and hours used to determine the standard labor rates. This is in light of HECO's position that the additions to staffing will be filled in place of incurring prior overtime levels. As indicated in response to CA-IR-76 discussions are continuing.

CA Adjustment C-20 reflects the overtime correction adjustment quantified by HECO, resulting from those discussions. The Company formally documented these calculations in HECO's response to DOD/HECO-IR-9-18.

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37 Information requests include: CA-IR-249, CA-IR-250, CA-IR-428, CA-IR-429, CA-IR-430 and CA-IR-431.

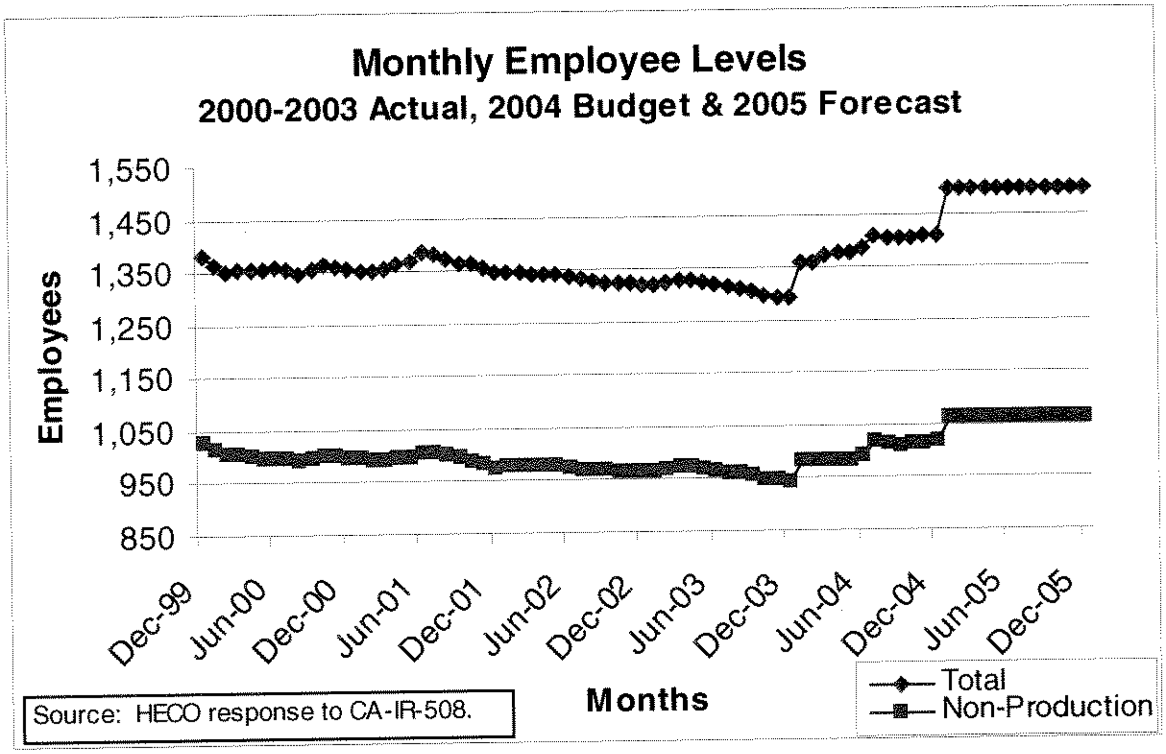
B. AVERAGE EMPLOYEE LEVELS.

Q. YOU PREVIOUSLY INDICATED THAT CA ADJUSTMENT C-21 RECOGNIZES "AVERAGE NON-PRODUCTION EMPLOYEE COUNTS FOR THE 2005 FORECAST PERIOD." WHY DOES CA ADJUSTMENT C-21 ONLY RELATE TO NON-PRODUCTION EMPLOYEE LEVELS?

A. In describing CA Adjustments C-8 and C-9, Mr. Brosch (CA-T-1) discusses proposed reductions to production expense (i.e., operations and maintenance) to reflect average employee levels for purposes of the 2005 test year forecast. Since Mr. Brosch is separately addressing production labor costs, CA Adjustment C-21 is limited to non-production employee levels, trends and labor costs plus production-related benefit costs not quantified by Mr. Brosch.

Q. AN EARLIER GRAPH ILLUSTRATED CHANGES IN HECO'S "AVERAGE" EMPLOYEE LEVELS SINCE 2000. HOW HAVE THOSE LEVELS CHANGED ON A MONTHLY BASIS SINCE 2000?

A. The following chart shows the historical and forecasted increase in HECO's monthly employee levels for both "Total" employees (including production) and "Non-Production" employees.



The employee counts during the period December 1999 through December 2003 represent actual employee levels. The 2004 (budget) and 2005 (forecast) levels represent HECO's estimates in the pending rate case. Clearly, the non-production employee counts increase substantially from the actual level at December 1993 (945) to the levels forecast in January 2005 (1,062) and December 2005 (1,063).

Q. REFERRING TO THIS MONTHLY EMPLOYEE CHART, IT APPEARS THAT HECO HAS ASSUMED THAT IT WILL ACHIEVE THE FORECAST EMPLOYEE LEVEL IN JANUARY 2005 AND MAINTAIN THAT LEVEL THROUGHOUT THE 2005 FORECAST YEAR. IS THAT CORRECT?

A. Yes, that is generally true. For both total employees and non-production employees, the aggregate employee count remains relatively static throughout the forecast test year.

Q. IS THIS ASSUMPTION REALISTIC?

A. No. It is common for employee vacancies and the hiring of new employees to result in overall headcount levels that fluctuate from month-to-month. This is particularly true when a company is in the process of transitioning from a self-imposed austerity program that constrained the hiring of employees to a more robust staffing environment.

Just as customer levels fluctuate from month-to-month, so do employee levels. While the test year matching concept is discussed in greater detail by Mr. Brosch (CA-T-1), it would be highly inconsistent and improper to intentionally set utility rates on an overall cost of service that fixes employee counts at hypothetical end-of-period forecast levels, while not similarly annualizing for customer growth or increasing energy usage expected to occur in the forecast year. Overall revenue requirement should consistently reflect either an average or end-of-period test year approach – not merely represent a result that relies on selectively choosing between both test year approaches for discrete elements of the ratemaking equation.

In discussing production expense, Mr. Brosch (CA-T-1) also refers to HECO's responses to CA-IR-14 and CA-IR-242, regarding differences between the 2005 operating budget the Company prepared for internal management purposes and the 2005 test year forecast prepared for the rate case. As indicated in the response to CA-IR-14, the 2005 internal operating budget included a downward adjustment to O&M expense to recognize an "Even Hiring Lag" approach to consider the normal "lag in the hiring process for positions included in the updated 2005 budget (even with the lag, the 2005 yearend employee count is still assumed to be attained)." The "Even Hiring Lag" adjustment process "started with a projected 2004 year-end employee count and assumed that positions would be filled evenly throughout 2005 to get to the year-end budgeted employee count."

Unfortunately, this "Even Hiring Lag" approach was not recognized in HECO's 2005 test year forecast. As stated in the response to CA-IR-14, HECO's starting point for the 2005 O&M expense estimate filed with the Commission was the 2005 annual budget, initially developed in 2003 and revised in early 2004. This 2005 O&M expense budget was then further adjusted[38] to determine the 2005 test year estimate. Only after the 2005 test

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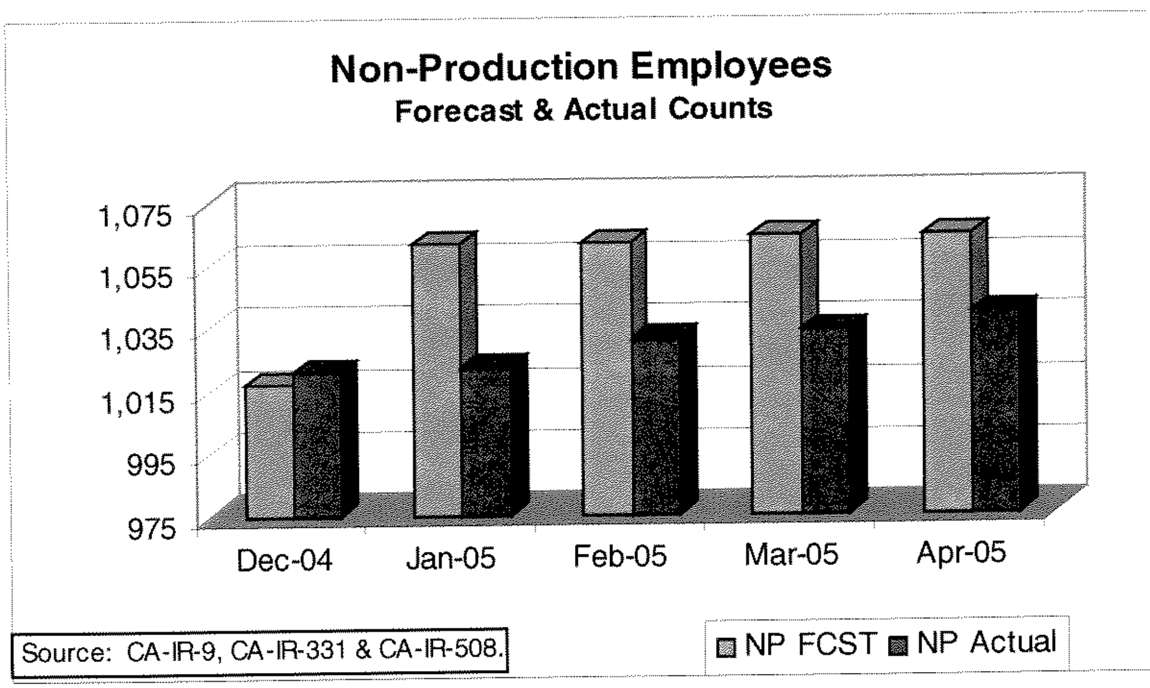
38 Adjustments include: issue simplification [eliminate non-qualified pension expense, incentive compensation, 401(k) administration, service awards ad executive life], reflect "normal" ongoing expenses, and include DSM utility incentives.

year forecast was "frozen" did HECO recognize further adjustments, such as the "Even Hiring Lag," in determining the 2005 operating budget.

Q. HOW DOES HECO'S FORECAST OF NON-PRODUCTION EMPLOYEE LEVELS COMPARE WITH ACTUAL COUNTS THUS FAR IN 2005?

A. In response to CA-IR-9 and CA-IR-331, HECO provided actual employee levels by month, including December 2004 through April 2005. The following chart compares the actual number of non-production employees during these months with the comparable budget (2004) and forecast (2005) levels HECO has included in the 2005 test year forecast.



While HECO has added new employees during the first four months of 2005, the "Even Hiring Lag" approach embedded in HECO's 2005 operating budget more accurately depicts reality than does the rate case assumption that the year-end employee level would be achieved on January 1, 2005.

Q. HOW DID YOU QUANTIFY CA ADJUSTMENT C-21?

A. During the course of this proceeding, the Consumer Advocate submitted numerous information requests in order to evaluate various factors influencing overall labor costs, including departmental reorganizations, employee transfers, job postings and the status of filling open positions, and future hiring plans. Mindful of the complexities of this analytical process, the Consumer Advocate received HECO's response to DOD/HECO-IR-8-8 via email late on June 17, 2005. This response contained HECO's estimate of the wages and benefits of seventy-five (75) "open positions" included in the Company's 2005 test year forecast.[39] Of these open positions, Mr. Brosch will address the Consumer Advocate's ratemaking treatment of the production positions, while I address the remaining non-production positions.

With this information, CA Adjustment C-21 adopted the "Even Hiring Lag" approach embedded in HECO's 2005 operating budget and removed one-half of the wages and benefits the Company estimated for the 35 "open" non-production positions.

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[39] For purposes of responding to DOD/HECO-IR-8-8, HECO considered a position as being "open" if the December 2005 forecasted employee count exceeded the actual December 2004 employee count on a departmental basis.

Q. IN QUANTIFYING THE AVERAGE HEADCOUNT ADJUSTMENT, DOES CA ADJUSTMENT C-21 ALSO CONSIDER EMPLOYEE-RELATED BENEFIT COSTS?

A. Yes. The response to DOD/HECO-IR-8-8 quantified both the wages and benefits of the "open positions,"[40] which was incorporated into the quantification of CA Adjustment C-21.

X. EMPLOYEE BENEFITS.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-22?

A. CA Adjustment C-22 (Exhibit CA-101) revises the forecast of employee benefits to recognize updated participant data, premium rates and actuarial studies. In effect, HECO-1502 has been revised accordingly. CA Adjustment C-22 recognizes the net effect of the updates and revisions provided by HECO.

Q. WHAT IS THE SOURCE OF THE REVISED FORECAST ON WHICH CA ADJUSTMENT C-22 IS BASED?

A. The Department of Defense submitted DOD/HECO-IR-9-2 for confirmation and clarification of various revisions and updates HECO had indicated were necessary in response to various other informational requests and in the

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40 In order to simplify the quantification process, CA Adjustment C-21 also removes the benefit-related costs of the average production employee adjustment included in CA Adjustments C-8 and C-9.

Company's May 5 Update Letter.[41] With regard to a requested confirmation of the anticipated employee benefit revisions, HECO responded to DOD/HECO-IR-9-2(o) by referring to the Company's revised test year forecast of employee benefit expenses as contained in Attachment 8 to a letter to the Consumer Advocate and Department of Defense dated June 15, 2005 ("June 15 Update Letter"). It is this information that serves as the basis for CA Adjustment C -22.

Q. YOU INDICATED THAT CA ADJUSTMENT C-22 IS BASED ON UPDATED PARTICIPANT DATA. COULD YOU EXPLAIN THAT REFERENCE?

A. Yes. The package of benefits HECO offers to its employees contains various options from which an employee-participant can choose. For example, there are several medical providers who offer coverage to HECO's employees. For purposes of the revised forecast of benefits expense provided in the June 15 Update Letter, HECO recognized January 1, 2005 enrollment data and actual 2005 premium rates, as available.

Q. DOES THAT MEAN HECO'S PROPOSED PAYROLL COST FORECAST IS BASED ON FORECASTED DECEMBER 2005 EMPLOYEE COUNTS FOR

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41 A letter dated May 5, 2005 ("May 5 Update Letter") to the Consumer Advocate and Department of Defense, in which HECO identified and described various planned updates and revisions the Company intends to recognize in its rebuttal filing.

THE ENTIRE 2005 TEST YEAR, BUT EMPLOYEE BENEFIT COSTS REFLECT EMPLOYEE LEVELS AT JANUARY 2005?

A. No. The reference to updated enrollment data refers to the distribution of employee participant elections among, and between the various benefit options offered by the Company. HECO's June 15 Update Letter does recognize the constant employee count the Company has recognized in its 2005 labor cost forecast.

XI. RESEARCH & DEVELOPMENT.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-24?

A. In the May 5 Update Letter to the Consumer Advocate and Department of Defense, HECO identified a planned rebuttal adjustment to research and development (R&D) expense, based on its response to CA-IR-536. CA Adjustment C-24 adopts this change proposed by HECO and removes the cost of the Green Power Program from the Company's test year R&D expense forecast.

Q. PLEASE EXPLAIN HECO'S PROPOSED REDUCTION TO R&D EXPENSE?

A. According to HECO's response to CA-IR-536, the 2005 test year forecast included a "placeholder" in the amount of $249,000 "for local research development funding used to match the estimated EPRI Tailored Collaboration (TC) funding." Subsequent to the Company's filing, the EPRI program funding has been finalized and HECO has determined that some of the R&D matching amounts had been included in the budgets of other HECO departments. As a result, CA-IR-536 proposed to remove $96,500 from Account 9302.

Q. PLEASE DESCRIBE THE GREEN POWER PROGRAM AND EXPLAIN WHY THE COST OF THIS PROGRAM HAS BEEN REMOVED FROM THE 2005 FORECAST.

A. Mr. Alan Hee (HECO T-10, p. 4) describes several Company adjustments to Account 910, Customer Assistance expense, as follows:

> First, estimated expenses for the Technology Division were reduced by $250,000 to correct an inadvertent double counting of expenses for the Green Power program. The non-labor O&M Expense Budget for the Administrative Division of the Energy Services Department (Account 910) already includes $100,000 for the development of this new initiative. A Green Power program would give customers an option to purchase energy with renewable or green attributes. As more renewable resources are developed, utilities have found that customers are interested and willing to pay a premium rate for electricity generated from those sources. The funds collected from customers through the Green Power program would be invested back into the community in a variety of research, educational, and social arenas. HECO has not yet determined the details of this program, but expects to use the funds included in the O&M Expense Budget to develop those details.

CA-IR-79 was submitted specifically to address certain statements contained in this testimony. In response, HECO indicated that it "does not have any specific initiatives under consideration at this time" and that the response to CA-IR-2 (HECO T-10, page 5) "explains that the details of the program have not yet been determined." Absent specific plans, initiatives or objectives, the Consumer Advocate is unable to recommend recovery of these costs, whether ultimately committed to preliminary consulting evaluations or other yet undefined applications.

In the event that HECO continues to seek recovery of these undefined costs, the Company's rebuttal testimony should present detailed program plans, address the recurring "ongoing" nature of the forecasted cost, and outline tangible benefits that can be reasonably expected to result from this Green Power program.

XII. <u>CUSTOMER SERVICE REORGANIZATION</u>.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-19.

A. In the May 5 Update Letter to the Consumer Advocate and Department of Defense, HECO described certain updates and revisions it intends to recognize in its rebuttal filing. One of the expense revisions was identified as a 2004 customer service reorganization identified by Mr. Alan Hee (HECO T-10, p. 2) and described in HECO's response to CA-IR-78. CA Adjustment C-19 increases test year expense to recognize HECO's estimate of the cost of this reorganization.

Q. PLEASE BRIEFLY EXPLAIN THE CUSTOMER SERVICE REORGANIZATION.

A. In June 2004, HECO reorganized this area of operation by creating a new Customer Solutions organization, headed by the Vice President Customer Solutions, a new position. The Vice President, Customer Solutions will oversee the revised Energy Services Department as well as three former divisions of Energy Services (i.e., Customer Technology Applications, Marketing Services, and Forecasts & Research) and the IRP Division. Several additional positions were added and one was eliminated as a result of the reorganization.

As described by HECO T-10, the added costs associated with this reorganization were not included in HECO's 2005 test year forecast, because of the limited time between the reorganization and finalization of the forecast. HECO T-10 also states that the Company will include the cost of this reorganization in rebuttal testimony.

Q. SUBSEQUENT TO THE MAY 5 UPDATE LETTER, HAS HECO REAFFIRMED ITS INTENTION TO REFLECT THESE ADDITIONAL CUSTOMER SERVICE COSTS IN ITS REBUTTAL FILING?

A. Yes. In response to DOD/HECO-IR-9-2(h), the Company indicated that it will increase the test year O&M expense by $504,660 to recognize the labor, non-labor and benefit costs associated with this change. The Consumer

Advocate has reviewed the Company's forecast support and concluded that the forecast amount does not appear to include any duplicative charges or unnecessary wage/benefit costs. As a result, CA Adjustment C-19 adopts the Company's proposed forecast update.

XIII. ALLOCATION OF HEI CHARGES TO HECO.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-16.

A. CA Adjustment C-16 recognizes another forecast revision HECO identified in the May 5 Update Letter to the Consumer Advocate and Department of Defense concerning revisions to the forecast of HEI costs allocated to HECO.

Q. PLEASE EXPLAIN.

A. In response to CA-IR-419, the Company revised the 2005 test year forecast of HEI costs billed to HECO to reflect more current allocation factors and revised estimates using 2004 data for the forecast base.[42] In response to CA-IR-419, HECO stated that the primary factors contributing to the $94,756 increase in its share of HEI costs, include: higher auditor attestation fees related to the requirements of Sarbanes-Oxley, higher reporting, pension, stock transfer, board of directors and community relations costs. After reviewing the revised

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[42] HECO-1310, as originally filed, used 2003 HEI cost data as the 2005 forecast base.

forecast support, CA Adjustment C-16 includes the increased forecast amount in cost of service.

XIV. KPMG AUDIT/ SOX CHARGES.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-25.

A. HECO's May 5 Update Letter to the Consumer Advocate and Department of Defense identified an increase in test year audit expenses, primarily KPMG fees, as a change the Company intends to recognize in its rebuttal filing.[43] CA Adjustment C-25 incorporates the identified revision into the Consumer Advocate's recommended revenue requirement.

Q. WHAT TYPES OF AUDIT FEES ARE PRIMARILY CAUSING THIS INCREASE IN TEST YEAR EXPENSE?

A. HECO-1310 represents the forecast of HEI billings to HECO that were included in the Company's 2005 test year operating expenses. In response to CA-IR-253 and CA-IR-424, the Company provided additional information and explanation regarding the external audit fees related to compliance with Sarbanes-Oxley. CA-IR-424 specifically sought additional information regarding ongoing cost levels. After reviewing the information supplied in response to these information requests, CA Adjustment C-25 recognizes the

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[43] HECO confirmed its intent to recognize the additional audit fees in response to DOD/HECO-IR-9-2.

Company's proposed increase in audit fees from $373,257 to $754,155, are recorded in NARUC Account 923.

Q. IN DESCRIBING CA ADJUSTMENT C-16, SARBANES-OXLEY AUDIT FEES IS ONE OF THE FACTORS SAID TO CONTRIBUTE TO THE INCREASE IN HEI FORECAST COSTS ALLOCABLE TO HECO. SINCE CA ADJUSTMENT C-25 ALSO INVOLVES SARBANES-OXLEY AUDIT FEES, DO THESE ADJUSTMENTS INVOLVE DUPLICATIVE COSTS?

A. Based on the information the Company has provided in response to various informational requests,[44] I do not believe that these adjustments contain duplicate charges. As indicated in response to CA-IR-424, KPMG LLP bills HEI, HECO, HELCO and MECO separately for the Sarbanes-Oxley ("SOX") audit work performed for each company, based on expended audit hours. Because of the different nature of the work occurring at HEI as compared to HECO, the SOX audit work involving HEI would involve different activities than the audit requirements associated with HECO's business activities.

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44 HECO responses to CA-IR-253, CA-IR-419, CA-IR-424, CA-IR-551 and DOD/HECO-IR-9-2.

XV. TAXES OTHER – SUTA REDUCTION.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-26.

A. In direct testimony, Mr. Lon Okada (HECO T-17, p. 4) stated that HECO's 2005 test year forecast included $202,000 of SUTA tax expense, based on a rate of 0.61%[45] and an employee wage base of $32,200. However, HECO's stand-alone SUTA tax rate was 0.00% in 2004, which should have been used in preparing the 2005 test year forecast. Mr. Okada indicated that HECO will remove the $202,000 set forth on HECO-1701, when HECO updates its overall revenue requirement in rebuttal testimony. CA Adjustment C-26 adopts HECO's proposed forecast revision.

Q. DID HECO'S MAY 5 UPDATE LETTER TO THE CONSUMER ADVOCATE AND DEPARTMENT OF DEFENSE ALSO IDENTIFY THIS FORECAST REVISION?

A. Yes.

XVI. INCOME TAX EXPENSE.

Q. HECO-1702 SHOWS HOW THE COMPANY QUANTIFIED THE AMOUNT OF INCOME TAX EXPENSE ASSOCIATED WITH ITS 2005 TEST YEAR FORECAST "AT PRESENT RATES," WHICH SUPPORTS THE PRO FORMA

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45 SUTA tax rate of 0.61% applies to HECO's affiliates, HELCO and MECO.

OPERATING RESULTS PRESENTED ON HECO-2301. HAS THE CONSUMER ADVOCATE PREPARED A CALCULATION OF INCOME TAX EXPENSE SIMILAR HECO-1702?

A. No. Referring to CA Schedule C (Exhibit CA-101), the amount of income tax expense has been separately calculated for each Consumer Advocate adjustment to operating income.[46] Using this presentation methodology, the Consumer Advocate Accounting Schedules clearly show the net operating income effect of each individual revenue and expense adjustment recommended by the Consumer Advocate.

However, during the course of our review of HECO's test year forecast, we identified several items that required separate adjustments to the Company's income tax expense forecast. As a consequence, separate Consumer Advocate adjustments are being proposed for the following items:

- CA Adjustment C-23: Amortization Of Debt-Related Costs.
- CA Adjustment C-27: Interest Expense Deduction.

Each of these adjustments will be discussed in separate testimony subsections.

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46 See CA Schedule C (Exhibit CA-101), pages 2 through 5, line 18.

A. AMORTIZATION OF DEBT-RELATED COSTS.

Q. WHAT IS THE PURPOSE OF CA ADJUSTMENT C-23?

A. CA Adjustment C-23 (Exhibit CA-101) reduces HECO's pro forma income tax expense to reflect the tax deductibility of amortizations associated with long term debt issuance and redemption costs, investment income differential and bond discount expense. Each of these "amortizations" was included in the development of HECO's proposed cost of debt and overall weighted cost of capital recommendations. Thus, the net cost of these amortizations is ultimately included within HECO's overall revenue requirement through the application of a weighted cost of capital, which considers such amortization costs, to HECO's proposed rate base.

Each of these amortizations is also recognized, at some point in time, in the development of the utility's federal and state taxable income. As such, the debt-related amortizations should have been considered and reflected in the calculation of HECO's pro forma test year income tax expense. However, as the Company indicated in response to CA-IR-381, the amortizations were inadvertently omitted from HECO's calculation of income tax expense for ratemaking purposes.

Q. SINCE HECO AGREES THAT THESE AMORTIZATIONS SHOULD BE RECOGNIZED IN QUANTIFYING TEST YEAR PRO FORMA INCOME TAX EXPENSE, WHY IS CA ADJUSTMENT C-23 NECESSARY?

A. As previously indicated, the starting point for the Consumer Advocate's quantification of overall revenue requirement is the Company's prefiled rate base and operating income recommendations. Since these amortizations were not reflected in the quantification of the Company's "as filed" income tax expense, it is necessary for the tax effect of these amortizations to be recognized by a separate Consumer Advocate adjustment.

Since HECO's response to CA-IR-381 indicated that the Company intends to include such amortizations in its cost of service update to be filed in rebuttal testimony, I will not elaborate on the need for or equity of recognizing the amortizations in the development of income tax expense for ratemaking purposes. Rather, I would simply note that the Consumer Advocate's proposed treatment of these items is consistent with the Consumer Advocate's weighted cost of debt proposal, as sponsored by Mr. David Parcell (CA-T-4).

B. INTEREST EXPENSE DEDUCTION.

Q. PLEASE DESCRIBE CA ADJUSTMENT C-27.

A. CA Adjustment C-27 quantifies the necessary adjustment to income tax expense associated with debt levels and related costs rates recommended by CA-T-4.

Q. IN QUANTIFYING CA ADJUSTMENT C-27, HAVE YOU EMPLOYED THE RATEMAKING TECHNIQUE COMMONLY REFERRED TO AS INTEREST SYNCHRONIZATION?

A. No. This method of annualizing or forecasting interest expense would effectively "synchronize" the interest deduction for income tax purposes with Consumer Advocate's weighted cost of debt and rate base recommendations, commonly referred to as "interest synchronization." Although it is my professional opinion that the interest synchronization approach should be employed for ratemaking purposes, the Consumer Advocate's filing does not use this method in deference to past Commission decisions[47] that have rejected this methodology in determining overall revenue requirement for Hawaii utilities.

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[47] Interest synchronization methodology. <u>Denied</u>: Docket No. 6531, D&O 11317, pp. 116-116 (HECO 1991 rate case); Docket No. 6998, D&O 11699, p. 98 (HECO rate case). <u>Allowed</u>: Docket No. 5114, D&O 8711, pp. 22-23 (Hawaiian Telephone Company).

Q. HOW DID YOU QUANTIFY THE AMOUNT OF INTEREST EXPENSE RECOGNIZED AS AN INCOME TAX DEDUCTION ON CONSUMER ADVOCATE ADJUSTMENT C-27?

A. Except for HECO's proposed capital lease treatment for the King Street leased property,[48] CA Schedule D (Capital Structure & Costs) reflects the updated and revised debt levels and cost rates proposed by HECO, as set forth on Exhibit CA-612 sponsored by Mr. Parcell (CA-T-4). Because the Consumer Advocate's starting point for quantifying overall revenue requirement is HECO's prefiled operating income, CA Adjustment C-27 is necessary to revise the amount of interest expense from the debt levels and cost rates embedded in the Company's original filing to the recently revised levels and rates.

Q. WHAT IS THE SOURCE OF THE REVISED INTEREST EXPENSE AMOUNTS SET FORTH ON CA ADJUSTMENT C-27?

A. HECO provided a series of spreadsheet files in support of the May 5 Update Letter. One of these spreadsheets contained revised capital structure and cost rate data, including updates to Exhibits HECO-2101 through HECO-2104. The revised interest expense amounts were obtained from these revised

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48 The Consumer Advocate recommends that the King Street lease be treated as an operating lease for ratemaking purposes, rather than the capital lease treatment proposed by HECO in its May 5, 2005 letter ("May 5 Update Letter") to the Consumer Advocate and Department of Defense describing certain updates and revisions the Company intends to recognize in its rebuttal filing. The operating lease treatment is discuss in a separate testimony section herein.

exhibits and compared to the amount of interest expense in the Company's original filing. In quantifying the income tax expense impact, the change in interest expense was then multiplied by the composite federal and state income tax rate.

C. INTEREST SYNCHRONIZATION.

Q. YOU PREVIOUSLY REFERRED TO THE CONCEPT OF "INTEREST SYNCHRONIZATION." COULD YOU PLEASE DEFINE THAT TERM?

A. Interest synchronization is a method which provides for the allocation of an interest expense deduction for income tax purposes to ratepayers equal to the ratepayers' contribution to the Company for interest expense, regardless of the Company's actual or estimated interest payments to its creditors. Since revenue requirement is partially driven by the application of a rate of return to the rate base investment, the Company will recover from its ratepayers an amount of interest expense equal to the effective weighted cost of debt embedded in that rate of return. Thus, ratemaking interest can be quite different from the actual interest expense, which might otherwise be deductible on a company's consolidated or stand-alone corporate tax return. Interest synchronization merely "synchronizes" the ratemaking tax deduction for interest with the interest expense ratepayers are required to provide the Company in utility rates – that is, through the ratemaking formula.

Q. DID THE COMPANY PROPOSE THE USE OF INTEREST SYNCHRONIZATION IN QUANTIFYING ITS PROFORMA LEVEL OF INCOME TAX EXPENSE?

A. No. While the Company's interest expense forecast is consistent with my understanding of past Hawaii regulatory practice, it is inconsistent with the ratemaking formula underlying rate base rate of return regulation.

Q. IF NEITHER THE COMPANY NOR THE CONSUMER ADVOCATE HAS RECOMMENDED THE INTEREST SYNCHRONIZATION METHOD IN DEVELOPING THEIR RESPECTIVE REVENUE REQUIREMENTS, WHY HAVE YOU FILED TESTIMONY DISCUSSING THE "INTEREST SYNCHRONIZATION" CONCEPT?

A. I have sponsored testimony supporting the use and application of the widely adopted interest synchronization method in multiple jurisdictions, including Hawaii, for over twenty years. However, because this Commission does not embrace that methodology and the Consumer Advocate has deferred to past Hawaii regulatory practice, it was necessary for my testimony to briefly discuss my support for this approach to quantify the ratemaking deduction for interest expense. In the event that the Commission were to reconsider its long-standing practice and ultimately adopt the interest synchronization approach in the current proceeding, Footnote (f) to CA Adjustment C-27 provides a quantification of the mechanics of the resulting adjustment to the Consumer

Advocate's recommended operating income, using the rate base and capital cost valuations included in the CA Joint Accounting Schedules (Exhibit CA-101), thereby appropriately synchronizing these revenue requirement elements. As filed by the Consumer Advocate, interest synchronization would result in additional interest deduction for income tax purposes of about $1.2 million, which would reduce income tax expense by about $467,000 and further reduce overall revenue requirement by about $839,000.

Q. HAVE YOU ADDRESSED THE SUBJECT OF INTEREST SYNCHRONIZATION IN PRIOR HAWAII RATE PROCEEDINGS?

A. Yes. I filed direct testimony on the interest synchronization issue on behalf of the Consumer Advocate in Docket No. 94-0298 (GTE Hawaiian Tel) and Docket No. 00-0309 (Citizens Communications dba The Gas Company). In both of those proceedings, the utility prepared its income tax expense calculations using an interest synchronization methodology. However, neither of those rate cases resulted in a Commission order, as dockets were resolved by negotiated settlement

D. THE AMERICAN JOBS CREATION ACT OF 2004.

Q. DOES THE CONSUMER ADVOCATE'S REVENUE REQUIREMENT RECOMMENDATION REFLECT ANY ADJUSTMENT TO CAPTURE THE IMPACT OF THE AMERICAN JOBS CREATION ACT OF 2004?

A. No. As Company witness Mr. Lon Okada (HECO T-17) states in pre-filed direct testimony, the American Jobs Creation Act of 2004 (hereinafter "the Act") was signed by President Bush in October 2004. Under the Act, electric utilities are deemed to be "U.S.-based manufacturers" which could effectively entitle them to a lower corporate income tax rate on the "production" element of their business. However, to be the best of my knowledge, there are no Treasury Regulations that provide guidance as to how the Act should be interpreted and how the added deductions should be calculated. In the absence of such guidance, I am not aware of any reliable method or approach to calculate the income tax savings that can reasonably be expected to result from the Act.

Q. DOES HECO OPPOSE THE RECOGNITION OF ANY SAVINGS TO BE DERIVED FROM THE ACT WITHIN THE DEVELOPMENT OF OVERALL REVENUE REQUIREMENT?

A. No. Mr. Okada's direct testimony (HECO T-17, p. 23) states an intent to include the effects of the Act within the Company's rebuttal filing, "subject to the issuance of guidance from the federal government."

Q. IN THE EVENT THE GUIDANCE ANTICIPATED FROM THE RELEASE OF FORTHCOMING TREASURY REGULATIONS ARE NOT AVAILABLE IN TIME FOR CONSIDERATION WITHIN THE COMPANY'S REBUTTAL FILING OR IN THE DEVELOPMENT OF REVENUE REQUIREMENT RESULTING FROM THIS PROCEEDING, DO YOU HAVE AN ALTERNATIVE RECOMMENDATION FOR THE COMMISSION TO CONSIDER IN HOW THIS ISSUE SHOULD BE HANDLED FOR RATEMAKING PURPOSES?

A. Yes. If the impact of the Act cannot be quantified for consideration in the Company's rebuttal filing or if the savings cannot be calculated and agreed to by the parties to this proceeding prior the issuance of the Commission's final order in this docket, I recommend that the Commission direct the Company to establish deferral accounts to capture any savings derived from the Act that have been excluded from the development of overall revenue requirement. These deferred savings would be subsequently provided as a benefit to ratepayers. This approach is comparable to utility requests for regulators to allow for the deferral of significant "expenses" believed to <u>not</u> be recovered within existing rates. The Consumer Advocate's proposal with regard to the tax savings resulting from the Act similarly provides a deferral mechanism for the "savings" not reflected in the development of overall revenue requirement.

Q. WILL ALL SAVINGS EXPECTED TO RESULT FROM THE ACT BE FULLY IMPLEMENTED WITHIN CALENDAR YEAR 2005?

A. No. The Act provides for a phasing in of the full benefits of the legislation over the multi-year period – 2005 through 2009. Thus, even if the parties are able to determine the appropriate income tax "savings" applicable for the 2005 test year, there should be additional tax savings in subsequent years.

Q. SHOULD HECO BE ENTITLED TO RETAIN "KNOWN" FEDERAL INCOME TAX SAVINGS THAT BECOME AVAILABLE IN BETWEEN RATE CASES?

A. At this point, I am unable to quantify the magnitude of the annual savings expected to be realized subsequent to this rate case. Generally, regulators should follow a consistent, symmetrical approach in granting deferral accounting authority. If a utility is typically allowed to defer costs or implement surcharge mechanisms to recover costs that are considered to <u>not</u> be collected through base rates, then it would logically and equitably follow that savings from events such as "known" federal income tax changes – not yet reflected in base rates – should also be deferred for future return to ratepayers.

XVII. <u>POTENTIAL ADIT RESERVE ADJUSTMENT</u>.

Q. HECO WITNESS MR. LON OKADA (HECO-T-17) BRIEFLY DISCUSSES A *POTENTIAL* ADJUSTMENT TO THE ACCUMULATED DEFERRED INCOME

TAX RESERVE. HAS THE CONSUMER ADVOCATE POSTED SUCH AN ADJUSTMENT TO ITS PROPOSED RATE BASE?

A. No. As Mr. Okada explains, an application has been made to the Internal Revenue Service ("IRS") for a proposed change in tax accounting methodology. As I understand the issue, IRS approval of the requested change in methodology would effectively allow the Company to "expense" or "deduct currently" certain expenditures that have previously been capitalized to plant in service for financial statement/ ratemaking purposes and for "tax" purposes. Over the life of a utility asset, the total amount of immediate "deductions" plus "tax depreciation" will not change. However, the pending application would accelerate the timing of the plant related depreciation plus immediate expensing of assets, resulting in significant additional cash flow.

Q. PLEASE EXPLAIN.

A. There are several significant differences between the "expenses" recorded for financial statement purposes and the "deductions" claimed on federal and state income tax returns. In general terms, HEI/HECO is able to deduct expenses more rapidly for "tax" purposes than what is "expensed" for financial statement and ratemaking purposes. However, the temporary tax savings (i.e., reduced "current" income tax expense) stemming from the ability to accelerate the tax deductions are not immediately "flowed through" to the benefit of current customers, but are retained by the Company via the recording of "deferred" income tax expense and "accumulated" within balance sheet accounts generally referred to as Accumulated Deferred Income Tax ("ADIT") Reserves.

In general terms, this "normalization" method of income tax accounting results in the recording of total income tax expense (i.e., sum of current and deferred income tax expense) that is usually higher than the actual taxes paid to federal and state taxing authorities (i.e., current income tax expense), with the tax effect of the underlying timing differences being recorded in the ADIT Reserve accounts. As such, the ADIT Reserve balance represents a source of cost free capital to the utility that is appropriately recognized as a reduction to rate base.

With regard to the book/tax "timing" differences, the acceleration of "tax deductions" in excess of financial statement "expense" amounts will eventually turn around on an item by item basis, such that the "tax deductions" will eventually become less than the book "expenses" causing actual taxes payable to increase. At the time of this "turnaround" (i.e., when tax deductions become less than book expenses), the timing difference causes "current" tax expense to increase and "deferred" income tax expense to decrease, resulting in a reduction to the credit balance in the ADIT reserve accounts.

In the context of the *potential* ADIT Reserve adjustment, IRS approval of the pending application would not change the amount of total income tax expense recognized for ratemaking purposes. However, IRS approval would result in a fairly significant additional tax deduction (and cash flow benefit) decreasing "current" income tax expense, increasing "deferred" income tax expense and increasing the ADIT Reserve balance that should be reflected as an additional rate base offset.

Q. WHEN WILL THE IRS MAKE ITS DETERMINATION?

A. I do not know. However, if a favorable decision is available prior to the Company's rebuttal filing, the impact of such decision should be identified in rebuttal testimony and recognized as a reduction to HECO's revised rate base. If a favorable decision is received subsequent to the filing of HECO's rebuttal testimony but prior to the Commission's order in this case, the parties should attempt to quantify and verify the impact of the IRS determination and file a jointly sponsored document notifying the Commission of the appropriate ADIT Reserve adjustment that should be considered in the Commission's final rate base determination.

Q. DO YOU HAVE A RECOMMENDATION FOR CONSIDERING THIS ISSUE IF NO IRS DETERMINATION IS RECEIVED PRIOR TO THE TIME OF THE COMMISSION'S ORDER IN THIS CASE?

A. Yes. Because this item is believed to be significant and any tax "benefits" would accrue solely to the Company's benefit "between rate cases," I would recommend that this Commission order HECO to defer for future return to ratepayers any savings realized in the form of additional cost free ADIT Reserves.

Q. HOW WOULD YOU RECOMMEND SUCH "SAVINGS" BE CALCULATED AND ACCOUNTED FOR?

A. Any "savings," if they materialize, would be in the form of additional ADIT Reserves that should be recognized as an immediate reduction to the Company's otherwise calculated rate base. Currently, HECO is authorized to capitalize carrying costs (i.e., interest and equity return) in the form of an allowance for funds used during construction ("AFUDC") on capital projects during their construction phase, when such projects are not included within rate base. The capitalized AFUDC is then included in future rate base and recovered from ratepayers through depreciation expense.

The reduction in rate base resulting from the realization of significant, incremental ADIT Reserve balances, upon a favorable ruling from the IRS, should mirror – only from a savings perspective – the AFUDC return on construction period capital expenditures excluded from rate base. As such, it would be appropriate, equitable and symmetrical to require HECO to defer "carrying cost" savings associated with the incremental ADIT Reserves, using the same AFUDC cost rates to calculate the <u>negative</u> carrying costs. At the time of HECO's next retail rate application, such accumulated capital cost savings could be returned to ratepayers, vis-à-vis an amortization over a reasonable period of time.

Q. DO YOU HAVE ANY FURTHER COMMENTS ON THIS GENERAL SUBJECT?

A. Yes. The direct testimony of Company witness Shiraki (HECO T-13, pages 36-37) briefly discusses a $2,081,000 reduction HECO made to the 2005 test year forecast to remove certain "fees for tax planning consulting services provided by Deloitte and Touche LLP (D&T)." According to HECO T-13, D&T assisted HECO in the change in federal tax accounting methodology that, if approved, could ultimately benefit ratepayers through the potential ADIT reserve adjustment previously discussed.

Although HECO T-13 indicates that the Company is not requesting recovery of the D&T costs at this time, HECO does express its intent to add $416,000[49] of D&T consulting fees to the 2005 forecast test year, if the IRS approves the Company's application and it becomes appropriate to increase the ADIT reserve offset to rate base.

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49 The $416,000 represents a five-year amortization of the $2,081,000 of D&T consulting fees.

Q. DO YOU CONCUR WITH THIS ADJUSTMENT, IF THE IRS APPROVES THE COMPANY'S APPLICATION AND THE ADIT RESERVE OFFSET TO RATE BASE IS INCREASED?

A. This tentative amortization would only be appropriate under two conditions. First, that the actual fees paid to D&T are at least $2,081,000. Second, that the increase in any ADIT reserve offset to rate base reduces revenue requirement on a net present value basis by at least $2,081,000. In other words, the benefit to ratepayers must exceed the cost to pursue the change in tax accounting method.

XVIII. <u>CAPITAL STRUCTURE & COST RATES</u>

Q. COULD YOU BRIEFLY IDENTIFY THE CAPITAL STRUCTURE AND COST RATES PROPOSED BY CONSUMER ADVOCATE IN THIS CAUSE?

A. Yes. CA Schedule D of the CA Joint Accounting Schedules (Exhibit CA-101) sets forth the capital structure and cost rates recommended by both HECO[50] and the Consumer Advocate, including the return on equity recommended by CA witness Parcell (CA-T-4). For purposes of the Consumer Advocate's direct

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[50] The HECO forecast capital structure set forth on CA Schedule D represents the Company's original filed balances and cost rates, per HECO-2101. Although the Company has subsequently revised its capital balances and cost rates via HECO's May 5 Update Letter attached spreadsheet files, HECO has not updated or revised its overall revenue requirement as of the date CA finalized its direct testimony. Since the CA Joint Accounting Schedules start with HECO's most recent filing (i.e., the "original" filing) for purposes of posting the various adjustments recommended by the Consumer Advocate, it was necessary for CA Schedule D to recognize HECO's "as filed" capital structure and cost rates, in support of the Company's overall revenue requirement.

testimony and revenue requirement recommendation, CA Schedules A and D (Exhibit CA-101) employ the capital structure and cost rates sponsored by Mr. Parcell.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBITS

OF

STEVEN C. CARVER

STEVEN C. CARVER

Summary of Qualifications

EMPLOYER: Utilitech, Inc.
Regulatory and Management Consultants

POSITION: Vice-President

ADDRESS: 740 North Blue Parkway, Suite 204
Lee's Summit, Missouri 64086

PRIOR EXPERIENCE:

6/87 - Present	Utilitech, Inc.
4/83 - 6/87	Missouri Public Service Commission, Chief Accountant
10/79 - 4/83	Missouri Public Service Commission, Accounting Manager
6/77 -10/79	Missouri Public Service Commission, Regulatory Auditor

EDUCATION:

Central Missouri State University
Bachelor of Science Degree in Business Administration
Accounting Major (1977)

State Fair Community College
Associate of Arts Degree - Emphasis in Accounting (1975)

OTHER QUALIFICATIONS:

Speaker
- 1988 Missouri Public Service Commission Workshop
- 1990 Annual NASUCA/NARUC Convention (Orlando)
- 1996 Mid-Year NASUCA Meeting (Chicago)

Instructor
- 1994 Hawaii Consumer Advocate Regulatory Training Program
- 1997 Hawaii Consumer Advocate Telecommunications Training Program
- 1999 Overview of Utility Regulation (Hawaii)
- 2000 Telecommunications: Overview of Regulation (Arizona)

PRIOR TESTIMONIES: (See listings attached as Exhibit CA-201.)

STEVEN C. CARVER
SUMMARY OF QUALIFICATIONS

Education and Experience

I graduated from State Fair Community College where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting. Subsequent to the completion of formal education, my entire professional career has been dedicated to public utility investigations, regulatory analysis and consulting.

From 1977 to 1987, I was employed by the Missouri Public Service Commission in various professional auditing positions associated with the regulation of public utilities. In that capacity, I participated in and supervised various accounting compliance and rate case audits (including earnings reviews) of electric, gas and telephone utility companies and was responsible for the submission of expert testimony as a Staff witness.

In October 1979, I was promoted to the position of Accounting Manager of the Kansas City Office of the Commission Staff and assumed supervisory responsibilities for a staff of regulatory auditors, directing numerous rate case audits of large electric, gas and telephone utility companies operating in the State of Missouri. In April 1983, I was promoted by the Commission to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department, providing guidance and assistance in the technical development of Staff issues in major rate cases and coordinating the general audit and administrative activities of the Department.

During 1986-1987, I was actively involved in a docket established by the Missouri Public Service Commission to investigate the revenue requirement impact of the Tax Reform Act of 1986 on Missouri utilities. In 1986, I prepared the comments of the Missouri Public Service Commission respecting the Proposed Amendment to FAS Statement No. 71 (relating to phase-in plans, plant abandonments, plant cost disallowances, etc.) as well as the Proposed Statement of Financial Accounting

Standards for Accounting for Income Taxes. I actively participated in the discussions of a subcommittee responsible for drafting the comments of the National Association of Regulatory Utility Commissioners ("NARUC") on the Proposed Amendment to FAS Statement No. 71 and subsequently appeared before the Financial Accounting Standards Board with a Missouri Commissioner to present the positions of NARUC and the Missouri Commission.

In July of 1983 and in addition to my duties as Chief Accountant, I was appointed Project Manager of the Commission Staff's construction audits of two nuclear power plants owned by electric utilities regulated by the Missouri Public Service Commission. As Project Manager, I was involved in the staffing and coordination of the construction audits and in the development and preparation of the Staff's audit findings for presentation to the Commission. In this capacity, I coordinated and supervised a matrix organization of Staff accountants, engineers, attorneys and consultants.

Since commencing employment with Utilitech in June 1987, I have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water) and have been associated with regulatory projects on behalf of clients in twenty State regulatory jurisdictions.

Previous Expert Testimony

I have continued to appear as an expert witness before the Missouri Public Service Commission on behalf of various clients, including the Commission Staff. I have filed testimony before utility regulatory agencies in Arizona, California, Florida, Hawaii, Kansas, Indiana, Nevada, New Mexico, Oklahoma, Pennsylvania, Utah, and Washington. My previous experience involving major electric company proceedings includes: PSI Energy, Union Electric (now Ameren), Kansas City Power & Light, Missouri Public Service/ UtiliCorp United (now Aquila), Public Service Company of Oklahoma, Oklahoma Gas and Electric, Hawaiian Electric, and Sierra Pacific Power/Nevada Power.

Exhibit CA-201 summarizes the various regulatory proceedings in which I have filed testimony.

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2005 (June)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone of Missouri	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income, Affiliated Interest
Kansas City Power & Light	Missouri	PSC	ER-80-48	Staff	1980	Operating Income, Fuel Cost
Gas Service Company	Missouri	PSC	GR-80-173	Staff	1980	Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-80-256Staf	f	1980	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-85	Staff	1981	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-154	Staff	1981	Interim Rates
Gas Service Company	Missouri	PSC	GR-81-155	Staff	1981	Operating Income
Gas Service Company	Missouri	PSC	GR-81-257	Staff	1981	Interim Rates
Union Electric Company	Missouri	PSC	ER-82-52	Staff	1982	Operating Income, Fuel Cost
Southwestern Bell Telephone	Missouri	PSC	TR-82-199Staf	f	1982	Operating Income
Union Electric Company	Missouri	PSC	ER-83-163	Staff	1983	Rate Base, Plant Cancellation Costs
Gas Service Company	Missouri	PSC	GR-83-207	Staff	1983	Interim Rates
Union Electric Company	Missouri	PSC	ER-84-168/ EO-85-17	Staff	1984 1985	Construction Audit, Operating Income
Kansas City Power & Light	Missouri	PSC	ER-85-128/ EO-85-185	Staff	1983 1985	Construction Audit, Rate Base, Operating Income
St. Joseph Light & Power	Missouri	PSC	EC-88-107	Public Counsel	1987	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	IURC	38380	Consumer Counsel	1988	Operating Income
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2005 (June)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Dauphin Consol. Water Supply Co.	Pennsylvania	PUC	R-891259	Staff	1989	Rate Base, Operating Income, Rate Design
Southwest Gas Corporation	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TO-89-56	Public Counsel	1989 1990	Intrastate Cost Accounting Manual
Missouri Public Service	Missouri	PSC	ER-90-101	Public Counsel/Staff	1990	UtiliCorp United Corporate Structure/ Diversification
City Gas Company	Florida	PSC	891175-GU	Public Counsel	1990	Rate Base, Operating Income, Acquisition Adjustment
Capital City Water Company	Missouri	PSC	WR-90-118	Jefferson City	1991	Rehearing - Water Storage Contract
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
Public Service of New Mexico	New Mexico	PSC	2437	USEA	1992	Franchise Taxes
Citizens Utilities Company	Arizona	ACC	ER-1032-92-073	Staff	1992 1993	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-93-37	Staff	1993	Accounting Authority Order
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Acquisition Adjustment
Hawaiian Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-930074, 0307	Public Counsel/ TRACER	1994	Sharing Plan Modifications
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	39584	Consumer Counselor	1994	Operating Income, Capital Structure

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2005 (June)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Rate Base, Operating Income
Kauai Electric Division of Citizens Utilities Company	Hawaii	PUC	94-0097	Consumer Advocate	1995	Hurricane Iniki Storm Damage Restoration
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	40003	Consumer Counselor	1995	Rate Base, Operating Income
GTE Hawaiian Tel; Kauai Electric - Citizens Utilities Co.; Hawaiian Electric Co.; Hawaii Electric Light Co.; Maui Electric Company	Hawaii	PUC	95-0051	Consumer Advocate	1996	Self-Insured Property Damage Reserve
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	94-0298	Consumer Advocate	1996	Rate Base, Operating Income
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUD-0000214	Attorney General	1997	Rate Base, Operating Income
Arizona Telephone Company (TDS)	Arizona	ACC	U-2063-97-329	Staff	1997	Rate Base, Operating Income, Affiliate Transactions
US West Communications	Utah	UPSC	97-049-08	Committee of Consumer Services	1997	Rate Base, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2005 (June)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Missouri Gas Energy	Missouri	PSC	GR-98-140	Public Counsel	1998	Revenues, Uncollectibles
Sierra Pacific Power Company	Nevada	PUCN	98-4062 98-4063	Utility Consumers Advocate	1999	Sharing Plan
Hawaii Electric Light Co., Power Purchase Agreement (Encogen)	Hawaii	PUC	98-0013	Consumer Advocate	1999	Keahole CT-4/CT-5 AFUDC, Avoided Cost
Kansas City Power & Light Company	Missouri	MoPSC	EC-99-553	GST Steel Company	1999	Complaint Investigation
US West Communications	New Mexico	NM PRC	3008	PRC Staff	2000	Rate Base, Operating Income
Hawaii Electric Light Company	Hawaii	PUC	99-0207	Consumer Advocate	2000	Keahole pre-PSD Common Facilities
US West/ Qwest Communications	Arizona	ACC	T-1051B-99-105	Staff	2000	Rate Base, Operating Income
The Gas Company	Hawaii	PUC	00-0309	Consumer Advocate	2001	Rate Base, Operating Income, Nonreg Svcs.
Craw-Kan Telephone Cooperative, Inc.	Kansas	KCC	01-CRKT-713-AUD	KCC Staff	2001	Rate Base, Operating Income
Home Telephone Company, Inc.	Kansas	KCC	02-HOMT-209-AUD	KCC Staff	2002	Rate Base, Operating Income
Wilson Telephone Company, Inc.	Kansas	KCC	02-WLST-210-AUD	KCC Staff	2002	Rate Base, Operating Income
SBC Pacific Bell	California	PUC	01-09-001 / 01-09-002	Office of Ratepayer Advocate	2002	New Regulatory Framework / Earnings Sharing Investigation

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2005 (June)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
JBN Telephone Company	Kansas	KCC	02-JBNT-846-AUD	KCC Staff	2002	Rate Base, Operating Income
Kerman Telephone Company	California	PUC	02-01-004	Office of Ratepayer Advocate	2002	General Rate Case, Affiliate Lease, Nonregulated Transactions
S&A Telephone Company	Kansas	KCC	03-S&AT-160-AUD	KCC Staff	2003	Rate Base, Operating Income, Nonreg Alloc
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counselor	2003	Rate Base, Operating Income, Nonreg Alloc
Arizona Public Service Company	Arizona	ACC	E-10345A-03-0437	ACC Staff	2004	Rate Base, Operating Income
Qwest Corporation	Arizona	ACC	T-01051B-03-0454 & T-00000D-00-0672	ACC Staff	2004	Rate Base, Operating Income, Nonreg Alloc
Verizon Northwest Inc.	Washington	WUTC	UT-040788	Attorney General/ AARP/ WeBTEC	2004	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUD-200300076	Attorney General	2005	Operating Income
Hawaiian Electric Company	Hawaii	PUC	04-0113	Consumer Advocate	2005	Rate Base, Operating Income

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
HISTORICAL COMPARISON OF PENSION COSTS,
CONTRIBUTIONS & PREPAID PENSION ASSET BALANCES

Year	Beginning Pension Asset Balance	NPPC Accrual	Trust Contribution	Ending Pension Asset Balance
	(A)	(B)	(C)	(D)
1987	$ 480,499	$ 9,216,777	$ 8,736,278	$ -
1988	-	8,307,882	8,307,882	-
1989	-	9,007,061	9,007,061	-
1990	-	9,739,662	9,739,662	-
1991	-	10,617,695	10,617,695	-
1992	-	11,382,007	11,382,007	-
1993	-	10,939,516	10,939,516	-
1994	-	10,924,690	10,924,690	-
1995	-	6,408,000	9,058,124	2,650,124
1996	2,650,124	8,380,584	6,971,824	1,241,364
1997	1,241,364	7,117,179	5,876,355	540
1998	540	1,870,595	2,206,034	335,979
1999	335,979	(1,073,259)	0	1,409,238
2000	1,409,238	(19,322,692)	0	20,731,930
2001	20,731,930	(20,465,117)	0	41,197,047
2002	41,197,047	(15,655,436)	0	56,852,483
2003	56,852,483	5,894,495	13,394,248	64,352,236
2004	64,352,236	(1,546,921)	15,186,494	81,085,651
2005	81,085,651	4,416,000	0	76,669,651
		$ 56,158,718	$ 132,347,870	
1996-2005		$ (30,384,572)	$ 43,634,955	

Source: HECO response to CA-IR-337.

CA-T-3
DOCKET NO. 04-0113

DIRECT TESTIMONY AND EXHIBITS

OF

JOSEPH A. HERZ

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: **Fuel and Purchased Power Expense, Generation Efficiency Factor (Sales Heat Rate), Fuel Inventory, Energy Cost Adjustment Factor and Power Factor Adjustment in Rate Design**

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DIRECT TESTIMONY OF JOSEPH A. HERZ, P.E.

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, POSITION AND PLACE OF EMPLOYMENT.

A. My name is Joseph A. Herz. I am employed by Sawvel and Associates, Inc. (Sawvel). I am the owner and president of Sawvel, which is an independent consulting firm. Sawvel is located at 100 East Main Cross Street, Suite 300, Findlay, Ohio 45840.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. Exhibit CA-300 summarizes my professional experience and educational background.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Division of Consumer Advocacy ("Consumer Advocate" or "CA"), who is a participant in this proceeding to represent, advance and protect the interests of Hawaii's electric utility ratepayers.

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN REGULATORY ENGAGEMENTS BEFORE THE HAWAII PUBLIC UTILITIES COMMISSION ("COMMISSION") ON BEHALF OF THE CONSUMER ADVOCATE?

A. Yes. I testified on behalf of the Consumer Advocate in rate case proceedings involving Hawaiian Electric Company, Inc. ("HECO" or "Company") Docket No. 7766, Hawaii Electric Light Company, Inc. ("HELCO") Docket Nos. 7764, 97-0420 and 99-0207 and Kauai Electric Division ("KED") Docket No. 94-0097. In addition to these rate case engagements, I assisted the Consumer Advocate with its analysis, Statement of Position and/or testimony in various IPP purchase power agreements, IRP planning, resource additions and transmission improvements involving HELCO (Docket Nos. 7623, 97-0349, 98-0013, 99-0346 and 99-0355) and avoided energy cost calculation for a proposed wind facility on Kauai (Docket No. 01-0005). Most recently, I testified on behalf of the Consumer Advocate in the Commission's generic investigation of distributed generation ("DG") in Hawaii (Docket No. 03-0371).

Q. WHAT ARE THE FUNCTIONAL AREAS OF THE CONSUMER ADVOCATE'S PRESENTATION IN THIS DOCKET, FOR WHICH YOU ARE DIRECTLY RESPONSIBLE?

A. My direct testimony provides the Consumer Advocate's position on HECO's 2005 estimated test year fuel and purchased power expense, generation efficiency factor (sales heat rate), fuel inventory and energy cost factor at current rates based on the production simulation results described later in this testimony. In addition, my testimony addresses power factor adjustment in rate design.

Q. WHAT MATERIALS DID YOU REVIEW AS PART OF YOUR PREPARATION FOR THIS FILING?

A. The materials that I have reviewed are HECO's application, written direct testimonies, exhibits and workpapers, as well as the responses to various information requests submitted by the Consumer Advocate and Department of Defense.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

Yes, I am sponsoring Exhibits CA-301 through CA-315. A listing and description of my exhibits is provided in the table of contents at the beginning of this testimony.

II. <u>SUMMARY OF RECOMMENDATIONS.</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. It is my recommendation, based on the results of the independent production simulation that I conducted of HECO's system, that the Commission make the adjustments shown in Exhibit CA-301, and summarized below, to HECO's 2005 test year November 2004 direct testimony filing projections:

1. Fuel and Purchased Power Expenses – By using May 2005 oil prices, which represent a significant increase from the May 2004 oil prices used in November 2004 HECO direct testimony filing, the recommended fuel expense and purchased power expense for the 2005 test year should be increased by $156,939,000 and $69,777,000, respectively (see CA-301, Page 1).

   The Consumer Advocate's production simulation that was used to develop the recommended fuel and purchased power expense adjustments incorporated the following adjustments to HECO's November 2004 direct testimony filing proposals:

   a. Modification of generating unit heat rates reflecting HECO's most recent heat rate tests;
   b. calculation of "Company Use" energy usage at HECO's buildings and facilities based on historical average energy use (i.e., 2000 through 2004) rather than as a percentage of sales;
   c. modification of system loss calculations to reflect lower system losses (4.65%) as compared to HECO filed losses of 4.70%;
   d. use of the HECO May 2005 update fuel prices to determine the 2005 test year projections (see CA-302);
   e. removal of the Company's proposed CHP capacity and energy from the test year estimates;

f. inclusion of the DG capacity and energy that HECO proposes to install at various HECO substations beginning on October 1, 2005; and

g. increased retail sales from 7,842.8 GWh to 7,856 GWh to reflect the removal of CHP and DSM programs as provided in the HECO May 2005 update.

Each of the above adjustments is described in greater detail in Section III of my testimony. It should be noted that the Consumer Advocate's production simulation also produced different availability and dispatch results for some generating units than the Company's model for reasons other than the adjustments identified above. We have not reconciled these differences with HECO, however, the Consumer Advocate hopes to be able to reconcile production simulation modeling differences with the Company prior to the hearing in this proceeding. This matter is also explained in more detail in Section III of my testimony.

2. Sales Heat Rate – Based on the production cost simulation which the Consumer Advocate has conducted using the estimated 2005 test-year data described above, the fixed sales heat rate for the 2005 test year should be 11,072 Btu per kWh, which is an adjustment of 5 Btu per kWh to that recommended in HECO's November 2004 direct testimony filing. The 11,072 Btu per kWh rate should also be incorporated in the

Energy Cost Adjustment Clause resulting from this proceeding (see CA-301, Page 1).

3. <u>Fuel Inventory</u> – Utilizing a 35-day industrial oil supply level, HECO's requested inventory supply level for residual fuel oil inventory, and HECO's requested level of diesel fuel oil inventory including an allowance for the planned DG diesels, the Consumer Advocate's recommended test year fuel consumption and HECO's May 2005 fuel prices, the recommended fuel inventory to be included in the test year rate base is $43,701,000, an increase of $14,959,000 to HECO's November 2004 test year filing of $28,742,000 (see CA-301, Page 1).

4. <u>ECA Factor at Current Rates</u> – Based on the adjustments for fuel and purchased power expenses, HECO's November 2004 test year filing ECA factor at current rates of 2.586 cents per kWh should be adjusted and increased by 3.203 cents per kWh to 5.789 cents per kWh (see CA-301, Page 1).

5. Power factor adjustment charges and credits are addressed later in my testimony.

III. FUEL AND PURCHASED POWER EXPENSES.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF FUEL EXPENSE?

A. As shown in CA-301, Page 1, the Consumer Advocate recommends a test year projection of $449,643,000, which is comprised of fuel oil expense (see CA-304, Page 1) and fuel related expense (see CA-305, Page 1). CA-304, Page 1 shows the derivation of the Consumer Advocate's recommended test year fuel oil expense of $444,934,000. The test year fuel related expense consists of fuel handling, fuel trucking and Petrospect expenses and is $4,709,000 as shown in CA-305, Page 1.

Q. EXPLAIN HOW YOU DETERMINED YOUR RECOMMENDED TEST YEAR FUEL EXPENSE.

A. Fuel oil expense is derived by multiplying the estimated test year fuel consumption (in barrels) at each of HECO's generating plants by the May 2005 contract fuel prices for the type of fuel consumed at that plant (see CA-304, Page 1). With the exception of the fuel handling component of the fuel related expense, trucking costs (applicable to the Honolulu plant and the DG diesels in dollars per barrel) and Petrospect costs (in dollars per barrel) are also applied to the estimated fuel consumption (in barrels) at each of HECO's generating plants (see CA-305, Pages 2 and 3). The fuel handling component of fuel related expenses is the value reflected in HECO's May 2005 update (see CA-305, Page 1 and CA-IR-276).

To determine the test year fuel consumption at each HECO generating plant, I must first determine HECO's estimated 2005 test year energy requirements. Next, I must determine the portion of the energy requirements that will be provided by HECO purchases from the as-available resources and H-POWER. The balance of HECO's estimated 2005 test year energy requirements, after such purchases, are assumed to be provided by HECO's generating plants and purchases from Kalaeloa and AES.

To determine the amount of generation that will be produced by all of HECO's generating units, as opposed to the specific generation of Kalaeloa and AES, I needed to simulate the economical dispatch of the available generation from HECO, Kalaeloa and AES. This was done using a production simulation model.

The above resulted in the estimated test year fuel consumption of HECO's generation and the associated quantity of fuel that will be consumed at each of HECO's generating plants, as well as the amount of test year energy purchases from the independent power producers (i.e., the as-available, H-Power, Kalaeloa and AES).

Q. WERE YOU ABLE TO USE THE RESULTS OF THE PRODUCTION SIMULATION MODEL WITHOUT FURTHER ADJUSTMENTS?

A. No, the production simulation model results needed to be adjusted to account for differences in operation that cannot be captured in the model. This adjustment is known as the calibration factor, which is used to adjust the Btu output and subsequently the amount of fuel burned at each HECO generating plant as shown in CA-309, Pages 2 and 4. As described above and shown in CA-304, Page 1 and CA-305, Pages 2 and 3, an estimated fuel oil price, and estimated fuel trucking and Petrospect costs, are applied to the estimated test year fuel consumption (determined from the prior step) to arrive at the estimated 2005 test year fuel expense.

A. DETERMINATION OF THE TEST YEAR ENERGY REQUIREMENTS AND SOURCES OF ENERGY SUPPLY.

Q. HOW DID YOU DETERMINE HECO'S ESTIMATED 2005 TEST YEAR ENERGY REQUIREMENTS?

A. The determination of HECO's estimated 2005 test year energy requirements is set forth on CA-303, Lines 1 through 6. As shown on CA-303, the starting point of the process is HECO's forecasted sales for the test year. Next, the amount of energy that the Company will use at its buildings and facilities (referred to as "Company Use" and also referred to as "No Charge") is determined. Finally, the amount of energy that will be lost in the system as the power is transformed into the voltages required for transmission and distribution throughout the Company's system (referred to as HECO system losses (4.65%)) must be determined. The sum of the above three items represents the total system energy requirements, or the amount of power that must be generated by HECO's generation and the generation of the independent power producers who sell power to the Company.

1. The Consumer Advocate's 2005 Test Year forecasted sales for HECO.

Q. WHAT ARE HECO'S TEST YEAR FORECASTED SALES?

A. CA-303 contains a comparison of HECO's sales forecasts filed in November 2004 and updated in May 2005. HECO's estimated 2005 test year energy requirements filed in November 2004 are based on a forecasted sales level of 7,842.8 GWh, and was updated in May 2005 to a forecasted sales level of 7,856.0 GWh.

Q. WHAT IS THE CONSUMER ADVOCATE'S ESTIMATE OF HECO FORECASTED SALES?

A. As discussed by Mr. Brosch in CA-T-1, the Consumer Advocate adopted the HECO test year sales projection and adjusted for the removal of the DSM and CHP impacts reflected in the Company's May 2005 update.

2. The Consumer Advocate's estimated Company Use or No Charge for the 2005 test year.

Q. WHAT EXACTLY IS THIS COMPANY USE ENERGY THAT IS ADDED TO FORECASTED SALES?

A. Company Use energy involves electric energy use at HECO's buildings and facilities. Such energy use at HECO's buildings and facilities is included with forecasted sales and system losses to determine the amount of energy to be generated by HECO's generating units and purchased from others. Since the cost of supplying this "Company Use" is included in HECO's revenue requirements to be recovered from ratepayers, the amount of estimated test year energy use at HECO's buildings and facilities has an impact on the revenue deficiency and level of rate increase to be established in this proceeding. As shown in HECO-403, HECO included an estimate of 16.6 GWh of Company Use in its test year energy requirements.

Q. WHAT IS HECO'S TEST YEAR ESTIMATE OF COMPANY USE OR NO CHARGE?

A. HECO projected Company Use to be 16.6 GWh in the 2005 Test Year in its November filing and is anticipated to use 16.7 GWh in its May update rebuttal testimony filing. Using the Company's higher level of Company Use will result in an overstatement of generation and resulting fuel and purchased power expense for the 2005 test year.

Q. WHAT IS THE CONSUMER ADVOCATE'S TEST YEAR ESTIMATE OF COMPANY USE OR NO CHARGE?

A. As shown in CA-303, the Consumer Advocate's estimate of Company Use and losses is less than the levels that are expected to be projected by HECO when the Company presents its revisions and updates to the HECO November 2004 direct testimony filing. This results in a Net System input that is 5.6 GWh less than HECO's anticipated May 2005 update position.

Q. WHY IS THE CONSUMER ADVOCATE'S ESTIMATE OF COMPANY USE LOWER THAN HECO'S TEST YEAR ESTIMATE?

A. The difference results from the different approaches to determining the estimated test year values. HECO estimated Company Use for the test year as a percentage (i.e., 0.212%) of its forecasted sales (see HECO T-4, Page 12, Line 24 through Page 13, Line 3 and HECO-403). This percentage was based on the 1999 through 2003 five-year average of Company Use to sales (see HECO-WP-403, Page 1).

I relied on the historical levels of Company Use or No Charge to determine my test year estimate.

Q. IS HECO'S APPROACH TO ESTIMATING COMPANY USE REASONABLE FOR PURPOSES OF ESTABLISHING THE TEST YEAR REVENUE REQUIREMENTS IN THIS PROCEEDING?

A. No, it is not because HECO's actual Company Use for the period 2000 through 2004 has remained relatively constant as shown in the Table below.

	Company Use (kWh)	Total Recorded Sales (kWh)	No Charge % of Sales (%)
2000	15,514,884	7,211,760,196	0.215
2001	15,541,140	7,276,681,000	0.214
2002	15,379,093	7,390,366,793	0.208
2003	15,379,093	7,522,229,597	0.204
2004	15,520,824	7,732,833,588	0.201
Total 5-Year	77,335,034	37,133,871,174	0.208
5-Year Average	15,467,007	7,426,774,235	0.208

Source: HECO's response to CA-IR-153.

As shown on the above Table, Company Use has not increased in direct proportion or in relation to system sales. In fact, Company Use decreased from 0.215% to 0.201% of sales from 2000 to 2004.

Q. IN ADDITION TO THE INFORMATION REFLECTED IN THE TABLE ABOVE, WHAT DATA FURTHER SUPPORTS YOUR CONTENTION THAT THERE IS NO CORRELATION BETWEEN COMPANY USE AND SALES?

A. HECO's four-year (1990 through 1993) average Company Use at the time of HECO's 1995 rate case was 16.4 GWh (see CA-WP-401, Page 2 in Docket

No. 7766), which is more than the five-year (2000 through 2004) average Company Use of 15.5 GWh (see CA-303, Page 1) in the current rate case. The stipulated sales estimate for the 1995 test year in HECO's last rate case was 6,912 GWh (see Commission's Decision and Order No. 14412 in Docket No. 7766 filed December 11, 1995) versus the current rate case estimated 2005 test year sales of 7,856.0 GWh (see CA-303, Page 1). In other words, comparing HECO's 1995 rate case with the current 2005 rate case shows that HECO's Company Use declined 5.5% [(16.4 – 15.5) ÷ 16.4] while test year sales estimates increased 13.6% [(7856.0-6912.9) ÷ 6912.9].

Based on the above, I have concluded that Company Use is not directly related to forecasted sales, as inferred by HECO in its development of estimated 2005 test year energy requirements.

Q AT FIRST BLUSH, IT WOULD APPEAR THAT IT SHOULD NOT MATTER WHETHER ONE USES A HISTORICAL AVERAGE TO DETERMINE THE COMPANY USE OR NO CHARGE ENERGY FOR PURPOSES OF DETERMINING THE TEST YEAR PROJECTION. WHY IS THE CONSUMER ADVOCATE CONCERNED WITH HECO'S PROPOSED METHODOLOGY?

A. If HECO's methodology were followed, Company Use would continue to increase as Company Sales increase on a prospective basis. However, as shown in the table above, Company Use has not increased with sales. Rather, Company Use has decreased while sales have increased. Thus, while there may not be a material difference for the instant proceeding, the Commission needs to be careful about setting a precedence for using HECO's proposed methodology in future rate proceedings. The reason is that if one assumes a relationship of Company Use and sales exists, when no such correlation has been established, the Company will be able to overstate the Company Use energy and resulting fuel expense in future rate proceeding.

Q. HOW SHOULD COMPANY USE BE ESTIMATED FOR THE TEST YEAR?

A. Review of HECO-WP-403, Page 1, CA-IR-153 indicates that the level of Company Use has remained relatively constant. In the years 2000 through 2004, Company Use averaged 15.5 GWh. Accordingly, I have estimated test year Company Use at the average of Company Use since 2000 of 15.5 GWh. The five-year average is a better method for estimating Company Use for the 2005 test year as it represents a normalized level for rate setting purposes.

3. Estimate of System Losses for the test year.

Q. WHAT ARE SYSTEM LOSSES AND HOW ARE THEY INCURRED BY HECO?

A. During the transmission, distribution and transformation of electricity from HECO's power supply resources to HECO's customers, losses are incurred on the transmission and distribution systems. In addition, HECO incurs step-up transformation losses for power produced at its generating facilities. The purpose of the system loss factor is to estimate the amount of energy loss that must be added to forecasted sales and Company Use to determine HECO's total system energy requirements.

Q. HOW WAS THE LOWER SYSTEM LOSS FACTOR UTILIZED?

A. Forecasted sales and Company Use were adjusted by the system loss factor to arrive at the test year energy requirements to be provided by HECO's generating and purchase power resources. System losses are shown on Line 4 of Exhibit CA-303.

Q. PLEASE DESCRIBE THE LOSS FACTOR USED BY HECO.

A. As shown in HECO-403, system losses were computed at 4.70% of Net Energy to System. This loss factor is based on a system loss analysis prepared by HECO in 2003 to estimate the losses incurred on its transmission and distribution systems. Although this information is useful for cost of service and rate design purposes, it does not recognize the amount of total system losses that must be considered for production simulation model dispatch purposes.

Q. HOW DID HECO PROJECT THE TOTAL SYSTEM LOSSES THAT MUST BE CONSIDERED FOR PURPOSES OF DETERMINING THE TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. To account for the total system losses, HECO "trued up" the losses estimated in the HECO 2003 System Loss Analysis to actual system losses incurred in 2003.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH THE METHODOLOGY USED BY HECO TO DETERMINE THE TEST YEAR SYSTEM LOSS PROJECTIONS?

A. While the Consumer Advocate agrees that HECO's methodology is acceptable for purposes of determining the total system losses for production simulation modeling purposes; the Consumer Advocate is concerned that the methodology was applied to the results of an abnormally high year of system losses, which effectively results in an overstatement of the test year system losses and resulting fuel expense.

Q. WHAT IS THE BASIS FOR THE CONSUMER ADVOCATE'S CONTENTION THAT THE 2003 SYSTEM LOSSES ARE ABNORMALLY HIGH?

A. In response to CA-IR-153, HECO provided the system losses for the five-year period (2000 through 2004), as shown in the following table.

Historical System Losses
2000 - 2004

	Subtotal Net Generation & Purchased Energy	Unaccounted for & Losses	Loss % of Net-to-System
2000	7,589,408,582	362,133,502	4.77
2001	7,643,288,010	351,065,870	4.59
2002	7,757,698,671	351,952,785	4.54
2003	7,908,956,777	371,348,087	4.70
2004	8,126,998,053	378,643,641	4.66
Total 5-Year	39,026,350,093	1,815,143,885	4.65
5-Year Average	7,805,270,019	363,028,777	4.65

The data reveals that the 2003 losses were the second highest losses during this five-year period. Thus, relying on the 2003 system losses for purposes of determining the fuel and purchase power expenses in the instant proceeding is not reasonable, as the 2003 system losses do not represent the normal experience.

While on one hand it is not readily apparent to me why HECO's 2003 energy loss ratio would be higher than HECO's energy loss ratios for 2001, 2002 and 2004, it is not unusual in my experience to find the energy loss ratios computed for a utility system to fluctuate from year-to-year above and below a five-year averages. Sometimes, these year–to-year fluctuations can be attributable to changes or differences in meter reading schedules or cycles that cause the average loss ratio computation to appear to go up or down from one year to the next but really are the result of which year energy usage is recorded or accounted for by the utility.

By averaging over a five-year period, however, the year-to-year fluctuations would be leveled and reflect a reasonable, normalized level of estimated energy loss ratios to be used for ratemaking purposes. Relying on the abnormally high level of system losses for production simulation modeling purposes, as HECO proposes, results in an overstatement of the generation required to be produced and a corresponding overstatement of the fuel and purchased power expense for the 2005 test year.

Q. WHAT LOSS FACTOR IS THE CONSUMER ADVOCATE RECOMMENDING BE USED FOR PURPOSES OF DETERMINING THE TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. I used a loss factor of 4.65%, which was HECO's actual average loss factor for the last five-year period 2000 through 2004 (see CA-IR-153). The Consumer Advocate recommends using the five-year average system loss percentage because Total System Losses should not fluctuate significantly from one year to the next, nor should an above average loss factor be used in developing normalized expenses. Holding all other items equal, the use of a lower loss factor results in a decrease in estimated test year fuel expense.

Q. WHY DOES THE USE OF A LOWER LOSS FACTOR RESULT IN A DECREASE IN TEST YEAR FUEL EXPENSE ESTIMATES?

A. The lower the loss factor, the lower the estimate of system losses and energy required to be generated by HECO's generating units or purchases from Kalaeloa and AES. The decreased output required of HECO's generating units results in a decrease in test year fuel expense estimates.

4. Projected As-Available Energy for the test year.

Q. WHAT IS AS-AVAILABLE ENERGY?

A. As-available energy is that which is provided only when the resource is available. In the instant proceeding, the energy is provided by independent power producers, when such producers have the energy available for sale to HECO. In addition to the as-available producers, HECO purchases energy from the Honolulu Program of Waste Energy Recovery (H-Power) facility.

Q. WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY THE AS-AVAILABLE RESOURCES AND H-POWER?

A. HECO estimated that the as-available resources consisting of Chevron and Tesaro will provide 1 and 6 GWh, respectively, in the 2005 test year (see HECO-503). HECO's estimate was based on the five-year average of purchased energy from the two as-available producers as the test year estimate of the energy expected to be delivered (see HECO T-5, Page 5 and

HECO-504). The following table shows the information contained in HECO-504.

Purchased Energy from Chevron and Tesoro from 1999 to 2003 Annual kWh

	Chevron	Tesoro	Total
1999	597,025	5,022,982	5,620,007.00
2000	329,370	7,374,703	7,704,073.00
2001	341,846	6,512,832	6,854,678.00
2002	302,435	6,913,588	7,216,023.00
2003	2,105,228	5,449,573	7,554,801.00
Total 5-Year	3,675,904	31,273,678	34,949,582
5-Year Average	735,181	6,254,736	6,989,916

As shown by the above table, the amount of purchased energy from Chevron was 302,435 kWh in 2002, and in 2003, the amount of purchased energy was 2,105,228 kWh. Chevron has three cogeneration units that produce electricity primarily for its internal refinery requirements, with the excess electricity being sold to HECO. According to HECO, the increase in 2003 was due to Chevron's refinery being on maintenance during the April to May 2003 time frame, resulting in less internal usage (see CA-IR-147). During this time, the cogeneration units continued to operate, resulting in significantly more deliveries of electricity to HECO in April and May 2003, and consequently for al of 2003.

Q. DOES THE CONSUMER ADVOCATE HAVE ANY CONCERNS WITH HECO'S TEST PROJECTION FOR THESE TWO ITEMS?

A. No, the Consumer Advocate reviewed the information in the table and concluded that HECO's estimates are supported by the five-year historical performance of these purchases. Thus, the Consumer Advocate has adopted HECO's energy estimate of as-available resources for purposes of this proceeding.

Q. WHAT IS THE AMOUNT OF TEST YEAR ENERGY ANTICIPATED TO BE PROVIDED BY H-POWER?

A. HECO used power dispatch schedules, historical trends and contract requirements to forecast the test year energy from H-Power (see HECO T-5, Pages 4 – 5). HECO's test year forecast of purchased energy from H-Power assumes that the plant is shut down for three weeks in the spring for routine maintenance of each of the two boilers, and that each boiler is taken off line for additional maintenance in the fall and in the winter. HECO anticipates H-Power producing up to 46 MW at all hours of the day and night. During other months of the year, the H-Power plant is normally operating up to 46 MW during the off-peak period. HECO's estimate of 2005 test year energy to be available from H-Power is 340 GWh (see HECO-503). Information from HECO's 2003 calibration analysis indicates that HECO purchased 345 GWh from H-Power in 2003.

Later in my testimony, I will describe HECO's energy cost adjustment clause that provides a pass through to HECO's ratepayers of HECO's actual purchased energy mix and prices. Accordingly, any derivations in H-Power's actual energy purchases versus that estimated for the test year will be passed through to HECO's ratepayers. For purposes of this proceeding, I believe that HECO's estimate of test year energy purchases from H-Power is reasonable and the Consumer Advocate has adopted HECO's estimate for H-Power as presented in its filing.

5. Determination of the energy to be provided by HECO's generation and the generation from the independent power producers (i.e., Kalaeloa and AES)

Q. HOW ARE HECO'S GENERATING PLANT FUEL CONSUMPTION AND ENERGY PURCHASES FROM KALAELOA AND AES ESTIMATED FOR THE TEST YEAR?

A. HECO's estimated fuel consumption and the estimated energy to be purchased from Kalaeloa and AES for the test year is determined through the use of a computer production simulation model. The purpose of this model is to simulate the hour-by-hour operation of HECO's generation system by allocating forecasted generation energy requirements among the available HECO, Kalaeloa and AES dispatchable generating units to determine the amount of energy to be produced by each such units to serve the balance of HECO's energy requirements and associated costs.

The computer model, utilizing HECO's pre-defined unit commitment, economically dispatches HECO's generating units to be loaded in order of lowest to highest incremental cost of production for each unit. The computer model thus calculates the quantity of fuel that will be consumed by each generating unit based on the load to be carried by each unit, each unit's efficiency characteristics and the purchased power arrangements with Kalaeloa and AES. The total consumption for each HECO generating unit is the sum of fuel consumed for each hour of operation at that unit's hourly loading.

Q. PLEASE DESCRIBE THE COMPUTER MODEL USED BY THE CONSUMER ADVOCATE TO ESTIMATE THE QUANTITY OF TEST YEAR FUEL CONSUMPTION.

A. The computer production simulation model I have utilized is a model that has been developed within our firm and used by the Consumer Advocate to assess the reasonableness of the fuel and purchased power projections for the 1995 HECO rate case (i.e., Docket No. 7766). In both the 1995 proceeding and this proceeding, I compared the HECO dispatch model output reports to the independent results from my dispatch model to assess the reasonableness of the HECO model results.

Q. HOW DID YOU GO ABOUT DETERMINING THE REASONABLENESS OF HECO'S PRODUCTION SIMULATION MODEL RESULTS?

A. First, I requested generating unit and capacity and energy purchase information used by HECO as inputs to the Company's energy dispatch production simulation model through numerous information requests submitted on February 1, 2005. Other consultants for the Consumer Advocate requested information regarding the production system prior to this date. I also requested copies of HECO dispatch model output reports and summaries to obtain the dispatch model results on February 10, 2005 in CA-IR–124, as well as several other information requests that were issued to the Company on that date.

Next, using HECO's production simulation inputs from the Company's November 2004 direct testimony filing in our firm's production simulation model, I was able to benchmark our production simulation model results against HECO's own production simulation model results. The purpose of doing so was to confirm and verify that my production cost simulation model would produce similar results as presented by the Company.

Q. DID YOU RECEIVE ALL OF THE INFORMATION FROM HECO THAT YOU NEEDED FOR YOUR ANALYSIS?

A. Yes, but not in a timely manner as expected. As a result, my ability to perform a thorough review was impaired due to the time constraints of the filing date for the Consumer Advocate's direct testimony.

Q. WHEN DID YOU ULTIMATELY RECEIVE THE REQUESTED INFORMATION AND WHAT WERE SOME OF THE DIFFICULTIES ENCOUNTERED IN THE INSTANT PROCEEDING?

A. The final responses to my February 10, 2005 information requests were received April 18, well past the agreed upon three week time period for the submission of responses. Furthermore, when the responses were received, I noted that the input data files provided by HECO were different from the data files used in the 1995 rate case. Thus, I was not able to immediately understand the program inputs as initially anticipated.

In addition, the files that were provided by HECO were not the files used to prepare the Company's direct testimony filing and projections. Thus, additional discovery was submitted to obtain and understand the Company's production simulation data input files used to develop the results presented in the Company's November 2004 direct testimony filing and to clarify the information that was provided in response to the initial information requests.

Finally, within the last two weeks prior to the filing of my direct testimony, additional information was provided by HECO through telephone conference calls and e-mail transmissions. The result of the above is that the time in which I was able to analyze the Company's filing was significantly reduced from the anticipated time that would have been allowed under the agreed upon procedural schedule.

Q. IS IT NORMAL TO HAVE A NEED TO DISCUSS VARIOUS DATA INPUTS IN ORDER TO UNDERSTAND THE DIFFERENT DISPATCH MODEL RESULTS?

A. Yes, the process whereby the analysts exchange information and clarify the production simulation modeling data input and output is not unusual. What is unusual for the instant proceeding is that the time in which this exchange occurred was very late in the discovery process due to the fact that HECO did not provide all of the requested information in February and early March as expected.

Q. ARE THERE ANY OTHER CONCERNS WITH YOUR ABILITY TO INDEPENDENTLY ASSESS THE REASONABLENESS OF HECO'S TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. Yes, in April and May 2005, HECO indicated that it was going to update its November 2004 direct testimony filing to reflect items such as increased fuel prices, changed generator outage schedules and removal of CHP and inclusion of Distributed Generation diesels. To-date, the production simulation results of such HECO updates have not been provided. As a result, although I was able to consider the updates as inputs to my modeling, I am unable to determine whether my results are consistent with the results HECO will file presumably as its case-in-chief when the Company eventually incorporates these, and perhaps other, updates in its production simulation modeling and derives revised fuel and purchased power expenses for the test year.

Q. IN YOUR EXPERIENCE IN PRIOR RATE CASE PROCEEDINGS BEFORE THIS COMMISSION, WHAT HAS BEEN THE GENERAL PRACTICE WITH REGARDS TO UPDATED INFORMATION FOR PRODUCTION SIMULATION RESULTS?

A. To my recollection, the Company in the 1995 rate case, as well as HELCO and KED in other rate cases, provided the modeled results of the updates so that a comparison and analysis of the results could be made prior to the time the Consumer Advocate filed its Direct Testimony. This provided the Consumer Advocate with an opportunity to investigate and address any concerns with the revised projections made a part of the Company's rate request.

Q. WHAT IS THE CONCERN WITH NOT HAVING THE MODELING RESULTS OF THE UPDATED DATA PRIOR TO THE FILING OF THE CONSUMER ADVOCATE'S DIRECT TESTIMONY IF THE CONSUMER ADVOCATE COULD INCLUDE THE APPROPRIATE UPDATES IN ITS PRODUCTION SIMULATION RESULTS.

A. When the Company does not provide updated production modeling results, including the revised fuel and purchased power expense projections, until after the Consumer Advocate files its direct testimony and exhibits, the Consumer Advocate is unable to analyze the Company's revised position and include the results of such analysis and comparison for the benefit of the Commission in its direct testimony filing.

Therefore, unless the Consumer Advocate is given the opportunity to update its direct testimony filing after the Company presents its updated test year case, the Consumer Advocate is left procedurally with only Rebuttal Information Requests and cross-examination at the hearing to attempt to provide the Commission with the appropriate record to consider the merits of the Company's belated revisions to its test year. This is neither an efficient nor effective use of time and resources. Furthermore, the Company does not have the opportunity to address and dispute the Consumer Advocate's position in the Company's rebuttal testimony, if the Consumer Advocate is not able to state its results and conclusions in testimony and exhibits filed before the Company files its rebuttal testimony.

Q. HOW DOES THIS SITUATION DIFFER FROM REBUTTAL TESTIMONY THAT IS FILED BY HECO SUBSEQUENT TO THE FILING OF THE CONSUMER ADVOCATE'S DIRECT TESTIMONY?

A. Rebuttal testimony that I am familiar with addresses the conclusions and recommendations of the Consumer Advocate regarding the Company's case-in-chief, and does not necessarily raise new information, or a new position that was not available during the discovery process prior to the filing of direct testimony. The purpose would be to provide all parties to the proceeding with an opportunity to discover information that is necessary in the development of its position on the Company's rate case for the Commission's consideration and for the Company to have the opportunity to rebut such positions.

Q. DOES YOUR TESTIMONY INCLUDE A COMPLETE REVIEW OF ALL HECO FUEL AND PURCHASED POWER EXPENSES?

A. No, for the reasons previously stated.

Q. GIVEN THE CHALLENGES DESCRIBED ABOVE, EXPLAIN HOW YOU INDEPENDENTLY VERIFIED THE COMPANY'S PRODUCTION SIMULATION RESULTS?

A. Recognizing that dispatch model input information and fuel and purchased power expenses were available from the HECO November 2004 rate filing, but that only input information was available from the HECO May 2005 update, I focused on first independently verifying the fuel and purchased power expenses in HECO's November 2004 direct testimony filing. After comparing the fuel and purchased power expenses derived from my independent model to the HECO November 2004 filing, I performed an independent analysis of fuel and purchased power expenses using the HECO May 2005 updates.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR COMPARISON.

A. Exhibit CA-301, Page 1 provides a comparison of production simulation results using HECO's November 2004 direct testimony filing inputs (see Lines 1 through 6, Columns (a) and (b)). HECO's production simulation results estimate test year fuel expenses to be $854,000 less, and purchased power expense to be $1,288,000 higher, than my production simulation results under the same load and resource conditions. My production simulation results were similar to the HECO results although several generating units dispatched differently than the HECO dispatch model. Workpaper CA-WP-309 provides a comparison of the Consumer Advocate dispatch results compared to HECO dispatch results. The baseload generating units in the left half of the work paper (Page 1), B1, B2, B3, AES, K5, W7, K4, W8, K2, K3 and K1 dispatched approximately the same amount of energy when comparing between the HECO and Consumer Advocate results. Some of the small differences in energy generated were caused by the order in which the units were listed in the data file when the heat rate of units are the same as each other. However, my opinion of these differences is that they are negligible.

The generating units in the right-hand half of the work paper (Page 1) including K6, W9, W10, W6, H9, W5, H8, W4 and W3 dispatched differently than the HECO dispatch model results. However, these units are the higher cost peaking generators that do not generate as much energy as the baseload units in the left hand side of the work paper and thus, do not have a significant impact on the total costs of the system. So, while some of these units (W9, H9, W5, H8, W4, W3) dispatched significantly different amounts of energy than did the same units in the HECO model, the impact of these differences on fuel costs are negligible.

In summary, I believe my dispatch results and the HECO dispatch results are comparable and reasonable. These production simulation results represent a difference of less than 0.03% of estimated test year fuel and purchased power expenses.

Q. WHAT HECO INPUTS WERE REVIEWED TO ARRIVE AT THE ABOVE CONCLUSION?

A. The following are several items that are important to achieve an accurate dispatch model result: generating unit minimum and maximum capacities, forced outage rates, generating unit maintenance schedules, unit efficiency (heat rate) and variable operation and maintenance costs. The results of my review of each of these items will be discussed in the following sections of my testimony.

Q. BEFORE CONTINUING, DID YOU MODIFY ANY OF THE COMPANY'S INPUTS TO THE DISPATCH MODEL?

A. No, the inputs to my initial model were not modified because I wanted to independently assess the reasonableness of HECO dispatch results in its November 2004 rate filing.

Q. WHEN DID YOU MODIFY INFORMATION USED IN YOUR DISPATCH MODEL?

A. After receiving the May Update, I prepared a second dispatch case to independently estimate fuel and purchased power costs associated with the charges in the May Update. Because HECO indicated that it would be updating its dispatch analysis inputs in response to many information requests, I determined that it would be prudent to obtain the updated inputs and then assess their reasonableness. HECO provided a set of changes to its filing that is referred to as the "May Update".

Q. WHAT ITEMS DID YOU MODIFY IN THE MAY UPDATE?

A. The following is a list of the items that were incorporated into my model to derive the Consumer Advocate's test year fuel and purchase power expense:

- I incorporated the HECO updated unit heat rates because they represent more recent information than in the HECO November filing.
- I accepted the HECO updated fuel costs as fuel costs have increased since the November filing.
- I reviewed the HECO generating unit capacities and unit availability factors and forced outage rates provided in the May update and chose to use the capacities, forced outage rates and availability used in the November filing.
- I removed the DSM and CHP impacts consistent with the removal of the sales and costs associated with these programs as discussed by Mr. Brosch and Mr. Carver, in CA-T-1 and CA-T-2, respectively, and included the substation sited DG also discussed by Mr. Brosch.
- I chose to use the planned outage schedules from the November filing because the Company indicated it is a normal planned outage schedule. I reviewed the updated outage schedules, but found them to be similar to the schedules in the November filing. Thus, I adopted the schedule from the November filing.
- Finally, I did not include the variable operation and maintenance ("O&M") costs in my model.

The basis for my recommended inputs is discussed in the following sections of my testimony.

(a) Generating unit forced outage rates for the test year.

Q. WHAT WAS THE BASIS FOR THE GENERATING UNIT FORCED OUTAGE RATES USED IN THE HECO NOVEMBER FILING?

A. HECO used average forced outage rates for the five-year period 1999 through 2003. The HECO generating system average forced outage rate was 2.34% for this period.

Q. WHAT FORCED OUTAGE RATES DID HECO INCLUDE IN ITS MAY UPDATE?

A. HECO provided forced outage rates for each generating unit in 2004; the five-year average for 2000 through 2004 and forecasted forced outage rates for 2005 through 2009. The 2004 HECO system forced outage rate was 6.19%, well above the previous five-year maximum annual rate of 3.51% in 1999. The 2000 to 2004 five-year average was 2.87% and the 2005 through 2009 forecast was 2.89%.

Q. WHY DID YOU CHOOSE THE FORCED OUTAGE RATES FOR THE 1999 THROUGH 2003 HISTORICAL PERIOD?

A. I used the 1999 through 2003 period to be consistent with the HECO planned outage schedule provided in the November filing. I also view the 2004 forced outage rate of 6.19% to be inconsistent with the 1999 through 2003 five-year average. If the Company increases its maintenance staff at its power plants as it has indicated in its filing, forced outage rates should stabilize rather than increase. Thus, to be consistent with the recommended inclusion of the increased production maintenance costs in the test year revenue requirement, the lower forced outage should be reflected in determining the fuel and purchase power expense.

(b) Removal of the CHP and DSM impacts and inclusion of the company sited substation DG.

Q. WHAT OTHER CHANGES WERE INCORPORATED FROM THE MAY UPDATE?

A. HECO removed its proposed CHP from its model and instead included DG that is expected to be installed at HECO's substations. Although HECO indicates that the DG units would are not anticipated to be available for operation prior to October of 2005, HECO's May 2005 update states that HECO will model the DG for operation in the months of July, August, September and October in HECO's production simulation update (see HECO's May 2004 update, Attachment 1A, Page 5).

Q. WHEN DID YOU INCLUDE DG IN YOUR ANALYSIS?

A. I included DG in October to be consistent with test year revenue requirements addressed by Mr. Brosch in CA-T-1.

(c) Need to calibrate the production model results.

Q. DOES HECO ADJUST ITS DISPATCH MODEL RESULTS TO CALIBRATE THEM TO ACTUAL HISTORICAL COSTS?

A. Yes. HECO applies a calibration factor to the generating unit heat rates.

Q. WHY DOES HECO USE A CALIBRATION FACTOR ?

A. HECO witness T-4 indicates that the calibration factor is used to adjust fuel consumption results from the production simulation modeling for actual operating conditions that cannot be completely duplicated by the computer model (see HECO-T-4, Page 19).

Q. HOW DOES HECO DETERMINE THE CALIBRATION FACTORS?

A. HECO divides the actual generating plant net heat rate for a year by the simulated net heat rate determined from the production simulation modeling results for that same year. Then the Company uses the computed calibration factor to adjust its generating plant heat rates and fuel consumption calculated by the production simulation model to be used in the fuel expense.

Q. WHAT YEAR DID HECO USE TO CALCULATE THE CALIBRATION FACTOR?

A. For HECO's November 2004 direct testimony filing, the Company calculated calibration factors for 2003. In the HECO May 2005 Update, the Company indicates that it plans to use a calibration factor that reflects actual operations for 2004 (see HECO May 2005 Update, Attachment 2, Page 1).

As noted in HECO T-4, Page 20, I opposed the use of a calibration factor in HECO's last rate case (Docket No. 99-0207) contending that:

1. The use of a calibration factor inherently does not provide the utility with an incentive to improve the efficient operations of utility-owned generating units;
2. A calibration factor is not allowed in other jurisdictions that do not have direct pass-through fuel adders; and
3. The use of a calibration factor leads to the possible over recovery of revenues

In that proceeding, I also noted that HELCO applied a calibration factor to a 2000 test year base case which lacked historical actual operating data due to the drastically different generation mix included in the test year.

The Commission concluded that in lieu of elimination, it will allow f the continued use of calibration factors, but required HELCO, on a going-forward basis, to file with the Commission and Consumer Advocate, annual reports identifying the actual system value for each year, the computer model results, and the adjustment resulting from the calibration factor. This was done to provide the Commission and the Consumer Advocate with appropriate data and information to more effectively address this issue of whether the calibration factor should continue to be used for HELCO in future rate cases. This information must be filed in a report by the end of January for the preceding calendar year, unless ordered otherwise by the Commission. (see Decision and Order No. 18365 filed February 8, 2001 in Docket No. 99-0207).

In this proceeding, I would raise these same concerns to the Commission about the continued use of calibration factors; but recognize that the Commission has previously ruled to allow the continued use of the calibration factors. Therefore, I recommend that the Commission require HECO, and the other utilities under its jurisdiction for that matter, to provide the same reporting requirements as required of HELCO in its last rate case in order for the Commission and the Consumer Advocate to effectively address the issue of continued use of calibration factors in future rate proceedings; and, if so, the appropriate calibration factor to be utilized for ratemaking purposes.

Q. DO YOU AGREE THAT THE 2004 CALIBRATION FACTOR SHOULD BE USED FOR HECO'S 2005 ESTIMATED TEST YEAR IN THIS PROCEEDING?

A. No. The problem is that unlike HELCO, which has filed calibration factor reports for every year since 2000, the only calibration factors available for HECO at this time are for 2003 and 2004. Unfortunately, the Commission and the Consumer Advocate do not have the data and information to know whether the calibration factor computed for 2004 is any better or worse than the 2003 calibration factor, or whether HECO should even be allowed the continued use of the calibration factor.

Q. WHAT DO YOU RECOMMEND SHOULD BE USED FOR CALIBRATION FACTORS?

A. I recommend using an average of the 2003 and 2004 calibration factors so as to not slant the calibration factors based on conditions in a particular year. As previously stated, the Commission should require HECO to file annual calibration factor reports with the Commission and the Consumer Advocate.

Q. WHAT ARE THE RESULTING CALIBRATION FACTORS USING THE AVERAGE OF 2003 AND 2004?

A. The calibration factors that I recommend are included in CA-309, Page 4.

(d) Variable O&M costs.

Q. WHY DID YOU NOT INCLUDE VARIABLE OPERATION AND MAINTENANCE COSTS?

A. My model was designed to dispatch in the same manner as the HECO model that was used in the 1994 Rate Case. The HECO model used in the 1994 Rate Case also did not include variable operation and maintenance costs in the dispatch simulation.

Q. DOES YOUR DISPATCH ANALYSIS CALCULATE COMPARABLE RESULTS TO THE HECO MODEL INCLUDING VARIABLE OPERATION AND MAINTENANCE COSTS?

A. Yes. In this particular application of the model, the results are comparable because the variable operation and maintenance costs used by the HECO model for each generating unit are nearly the same (see CA-WP-306, Page 1). HECO's generating unit variable operation and maintenance costs range from a low of $0.443254/MWh to a high of $0.93681/MWh as compared to the fuel component of the dispatch cost of approximately $56/MWh in the November filing and $90/MWh in the May Update. Variable operation and maintenance is less than one percent of the fuel costs. Thus, variable operation and maintenance does not change the dispatch order.

Q. IS VARIABLE OPERATION AND MAINTENANCE USED ELSEWHERE IN YOUR TESTIMONY OR IN ECAC CALCULATIONS?

A. No. It is not. Thus, whether generation variable operation and maintenance is included in the dispatch model or not does not impact my results as compared to HECO's dispatch results.

Q. PLEASE SUMMARIZE YOUR POSITION REGARDING THE ESTIMATED TEST YEAR FUEL OIL EXPENSE.

A. My recommended test year fuel oil expense of $449,643,000 and purchased power expense of $334,429,000 are based on the May 2005 fuel oil prices provided by HECO in its May 2005 update. Test year fuel consumption is based on my production simulation model results. My production simulation utilized HECO's November 2004 direct testimony filing input data adjusted for:

a. modification of generating unit heat rates reflecting the results of HECO's most recent heat rate tests provided with HECO's May 2005 update;

b. calculation of "Company Use" energy usage at HECO's buildings and facilities based on a five-year historical average energy use rather than as a percentage of sales;

c. modification of loss calculations to HECO's five-year (2000 through 2004) average losses (4.65%) as opposed to HECO filed losses of 4.70%;

d. use of HECO's May 2005 fuel prices provided with HECO's May 2005 update;

e. revised projections of fuel handling and trucking costs as provided in HECO's May 2005 update;

f. use of the average of HECO's computed calibration factors computed using 2003 and 2004 production simulation versus actual results (HECO used the 2003 computed calibration factors in its direct testimony filing and indicated in the May 2005 Update that it plans to use the 2004 calibration factors when it updates its production simulation runs);

g. revised projections for various inflationary adjustment factors in certain of the purchased power agreements;

h. removed CHP capacity and energy from the estimated 2005 test year;

i. included DG capacity and energy beginning October 1, 2005; and

j. increased retail sales from 7,842.8 GWh to 7,856.0 GWh.

It is my understanding that HECO plans to update its November 2004 filing with its rebuttal testimony filing. While HECO has provided in May 2005 an indication of changes it intends to make to its production simulation inputs, HECO has not provided an update to its production simulation results utilizing these updated inputs. Therefore, I have not had the opportunity to review or comment on HECO's update positions until after my direct testimony has been filed. I will be reviewing HECO's rebuttal filing and anticipate updating my testimony after HECO provides an update to its November 2004 production simulation results in its rebuttal testimony.

B. PURCHASE POWER EXPENSE FOR THE 2005 TEST YEAR.

Q. WHAT IS PURCHASED POWER AND WHY MUST IT BE CONSIDERED IN DETERMINING THE TEST YEAR REVENUE REQUIREMENTS?

A. Over 40% of HECO's estimated 2005 test year energy requirements is projected to be purchased from independent power producers ("IPP") at an estimated cost of $368,341,000 (see CA-301, Page 1). The amount of energy estimated to be purchased by HECO from each IPP for the 2005 test year is summarized below:

IPP Provider	GWh Estimated to be Purchased by HECO
Kalaeloa	1,539.4
AES	1,527.0
H-Power	340.0
Tesoro	6.2
Chevron	0.7
Total	3,413.3

Source: CA-312, Page 1.

HECO's payments to the IPPs represent a purchase power expense incurred by the Company to meet its service obligations to its customers, the ratepayers. Accordingly, HECO's purchase power expenditures are included in HECO's test year revenue requirements for purposes of evaluating and setting rates for the Company.

Q. HOW IS PURCHASED POWER EXPENSE DETERMINED?

A. Each IPP has a purchase power agreement ("PPA") with HECO that sets forth the payment rates and the manner to determine the amount of HECO's payment to the IPP. Some of the IPP providers are considered firm capacity resources in HECO's power supply firm capacity resource planning and receive capacity payments from HECO in addition to energy payments for the energy output of the IPP's facility that is purchased by HECO. Other IPP providers are considered "as-available" resources and are not considered as a capacity resource and receive energy only payments. The following tabulation provides the type of resource, and the amount of HECO estimated test year energy and capacity payment, if applicable for each IPP under their PPA:

IPP Provider	Capacity (MW)	Capacity Payment ($000)	Energy Payment ($000)	Total Payment ($000)
Firm				
Kalaeloa	209	32,831	134,959	167,790
AES	180	68,561	87,446	156,007
H-Power	46	6,901	36,895	43,796
As Available				
Tesoro	N/A	N/A	672	672
Chevron	N/A	N/A	76	76
Total	435	108,293	260,048	368,341

Sources: CA-312, Page 1 and CA-313, Page 2

The Kalaeloa, AES and H-Power capacity payment terms and the Kalaeloa and AES energy payment terms are established by their respective PPA and are summarized in HECO-502, Page 1. The H-Power, Tesoro and Chevron energy payment terms are based on HECO's quarterly avoided energy cost (see CA-314, Page 2) for the Consumer Advocate's calculation of test year 2005 avoided energy cost payment rates.

Q. DID YOU REVIEW THE CHARGES FOR PURCHASED POWER INCLUDED IN HECO'S NOVEMBER FILING AND MAY UPDATE?

A. Yes. I reviewed charges associated with HECO firm power purchases that include AES Hawaii, Inc., Honolulu Program of Waste Energy Recovery ("H-Power") and Kalaeloa Partners, L.P. I also reviewed charges for as-available energy purchases from Chevron and Tesoro. In particular I reviewed the testimony of HECO witness Daniel S. W. Ching (HECO T-5), Director of Power Purchase Division.

Q. HOW ARE PURCHASE POWER CHARGES CALCULATED FOR THE AES, H-POWER AND KALAELOA PURCHASES?

A. Purchase power charges for these purchases are calculated in CA-312 and CA-313. Based on my review, these charges are consistent with the PPAs between HECO and each IPP.

Q. DO YOU RECOMMEND ANY CHANGES TO THE HECO DIRECT TESTIMONY PURCHASED POWER CHARGES?

A. Although I did not make any changes to the method by which HECO computed its estimated 2005 test year purchase power expense, my recommended purchase power expense of $368,341,000 is $69,777,000 higher than HECO's November 2004 direct testimony filing of estimated purchase power of $298,564,000. This increase is due primarily to the increase in purchase power prices under the PPAs due to the increase of over 50% in fuel oil prices from the May 2004 levels used in HECO's November 2004 direct testimony filing to the May 2005 prices used in the Consumer Advocate's direct testimony position. To a lesser extent, the difference in test year purchase power estimates is also attributable to different amount of energy estimated to be purchased from Kalaeloa and AES, and my use of the revised inflationary factors and availability factors provided with HECO's May 2005 Update (see CA-301, Page 2 Lines 13 through 18).

IV. GENERATION EFFICIENCY FACTOR (SALES HEAT RATE).

Q. WHAT IS THE GENERATION EFFICIENCY FACTOR OR SALES HEAT RATE?

A. The generation efficiency factor or sales heat rate is a measure, expressed in terms of Btu per kWh or MBtu per kWh, of the amount of fuel consumed in HECO's generation facilities to provide a kWh of energy measured at the customer's meter. The sales heat rate is used in the Energy Cost Adjustment Clause ("ECAC") to pass through increases and decreases in the composite weighted average cost of fuel consumed at HECO's generating plants (expressed in terms of cents per MMBtu) from that included in HECO's base rates to HECO's customers. Basically, the ECAC is an energy rate adjustment mechanism that passes through, after conclusion of a rate case, price changes in the Company's fuel and purchased energy cost and changes in the Company's generation and purchased energy mix from that used in arriving at the Company's test year revenue requirements and base rates in the rate case, without the need for the Company to file a new rate case.

Q. PLEASE DESCRIBE THE ECAC USED BY HECO.

A. The ECAC is a provision in the Company's rate schedule that allows HECO to apply a factor, referred to as the Energy Cost Acquisition Factor or ECA Factor, expressed in terms of cents per kWh, that increases or decreases ratepayer charges resulting from the Company's monthly ECAC calculations. HECO files its ECA Factor calculations with the Commission on a monthly basis. The two major components in the monthly ECA Factor calculation are the generation factor and the purchased energy factor, both of which are expressed in terms of cents per kWh. Exhibit CA-314, Page 1 provides the test year ECA Factor calculation under HECO's current rates.

The purchased energy factor is determined as the difference between HECO's weighted composite cost of purchased energy (computed as HECO's average cost of purchased energy prices multiplied by the percentage of sales provided by purchased energy) and the base weighted composite cost of purchased energy embedded in HECO's base rates. Similarly, the generation factor is the difference between HECO's weighted composite cost of fuel prices and the base weighted composite cost embedded in HECO's base rates. The calculation of the generation factor, however, is not as straight-forward as the purchased energy factor in that HECO's composite fuel price of fuel consumed at the Company's generating plants is expressed in terms of cents per MMBtu, which needs to be converted to cents per kWh for the ECA Factor to be applied to HECO's ratepayers. As previously stated, HECO's composite purchased energy prices is already expressed in terms of cents per kWh and therefore the calculation of the purchased energy factor does not require the interim conversion step needed for determining the generation factor.

Q. HOW IS THE SALES HEAT RATE UTILIZED IN THE ECA CLAUSE?

A. The sales heat rate is utilized to convert HECO's composite fuel prices of fuel consumed at the Company's generating plants, expressed in terms of cents per MBTu, to a composite cost of generation, in terms of cents per kWh, for determining the generation factor. The sales heat rate is essentially a measure of HECO's generation efficiency conversion of fuel consumed, expressed in terms of MBTu, to electricity produced and delivered by the Company's generating units to HECO's customers, expressed in terms of kWh. Accordingly, this generation efficiency factor or sales heat rate, expressed in terms of MBTu per kWh, is utilized to pass through fuel price increases or decreases experienced by HECO to the ratepayers. As a result, the sales heat rate has an impact on future customer billings.

Q. HOW IS THE SALES HEAT RATE DETERMINED?

A. The sales heat rate is determined by dividing test year fuel consumption by forecasted sales attributable to HECO's generation (see CA-306). Test year fuel consumption is taken directly from the results of the production simulation used to determine fuel expense. The amount of forecasted sales attributable to HECO's generation is calculated by multiplying forecasted sales by the ratio of HECO's system generation to total (i.e., net to system) energy requirements. In other words, the calculation of HECO's sales heat rate in this rate case proceeding will establish the fixed generation efficiency factor to be utilized in HECO's ECAC. Thus, the sales heat rate to be implemented in HECO's ECAC will correspond to test year resource mix utilized to determine HECO's revenue requirements and new rates in this proceeding.

Q. WHAT EFFECT DOES THE SELECTION OF THE SALES HEAT RATE HAVE ON FUTURE CUSTOMER BILLINGS?

A. The sales heat rate implemented as a result of this proceeding will have an impact on what HECO's customers will be charged for fluctuations in fuel prices in the future. Also, since the sales heat rate is determined by dividing fuel consumption by energy sales, the estimated Company Use energy and the estimated system loss energy discussed previously are implicitly incorporated into the sales heat rate. Accordingly, the charges to ratepayers for fluctuations in fuel prices will be based on the estimated Company Use and estimated system losses utilized to develop the sales heat rate. To the extent that the sales heat rate utilized in HECO's ECA clause is inconsistent with test year conditions upon which rates are determined, the cost of fuel passed on to

HECO's customers will likewise not be consistent with or track the basis on which such charges for electric service were developed.

Q. WHY IS IT IMPORTANT TO DETERMINE A NORMALIZED HEAT RATE FOR RATE SETTING PURPOSES WHEN A COMPANY LIKE HECO IS ALLOWED TO USE THE ECAC TO RECOVER THE COSTS ASSOCIATED WITH CHANGES IN THE PRICE OF FUEL OIL?

A. The sales heat rate will determine the amount to be paid by HECO's ratepayers (in cents per kWh) when HECO's composite generation fuel cost (in cents per MMBtu) is different than that used to set rates, and the base cost in HECO's ECAC. If HECO's sales heat rate is different than that used in the ECAC, the change in HECO's fuel expense will not match dollar-for-dollar the change in HECO's ECAC revenues. Thus, if the heat rate is overstated, HECO will be able to recover, through the ECAC, monies that are in excess of the fuel expense incurred to meet customers' energy needs. On the other hand, if the heat rate is understated, HECO will not be provided an opportunity to recover the fuel cost as intended through the ECAC.

Q. WHAT IS YOUR RECOMMENDED TEST YEAR SALES HEAT RATE?

A. The test year sales heat rate should be 0.011072 MBtu per kWh (see CA-301, Page 1), which is less than the generation efficiency factor of 0.011170 MBTu per kWh presently in HECO's current rates. By comparison, HECO's

November 2004 direct testimony filing determined the sales heat rate should be 0.011077 MBTu per kWh which is nearly identical to the Consumer Advocate's direct testimony position. The Consumer Advocate's sales heat rate is based on the availability, resource mix and use of various IPP and HECO generating resources, as described earlier in this testimony, used to develop estimated 2005 test year revenue requirements.

V. FUEL INVENTORY.

Q. PLEASE DESCRIBE WHAT IS SET FORTH ON EXHIBIT CA-308.

A. Exhibit CA-308 provides the derivation of test-year fuel inventory amounts based on my production simulation model results and HECO's May 2005 fuel prices. The methodology that I used for determining fuel inventory is shown in Exhibits CA-308, CA-309, CA-310, and CA-311 and is the same methodology utilized by the Company in its November 2004 direct testimony filing

Q. DID YOU REVIEW AND ASSESS HECO'S FUEL INVENTORY CALCULATIONS?

A. Yes. HECO maintains an inventory for Low Sulphur Fuel Oil (LSFO) that is used in HECO's steam generating units and for diesel fuel that is used in its combustion turbines and reciprocating diesel engine generating units.

Q. WHAT DOES HECO PROPOSE AS AN INVENTORY LEVEL FOR LSFO?

A. HECO proposes a 35-day inventory that is equivalent to an average daily LSFO consumption of 22,569 barrels of LSFO resulting in an inventory of 789,909 barrels of LSFO (See HECO-WP-409, Pages 39 to 42)

Q. DO YOU AGREE WITH THIS LEVEL OF INVENTORY?

A. No. I independently calculated LSFO inventory in CA-309, Page 1. Based on a 35-day inventory level, the number of barrels of LSFO is 780,354 which is 9,555 barrels less than HECO's filed inventory level.

Q. DO YOU AGREE WITH HECO'S STATED GOAL OF A 35-DAY INVENTORY LEVEL?

A. Yes. I reviewed HECO's Fuel Oil Inventory Study prepared by the HECO Power Supply Planning & Engineering Department of the Generation Planning Division dated December 23, 2003 included in HECO-WP-409. This study takes into account major disruptions in the fuel supply and delivery system that could affect the ability of HECO to reliably serve its customers without interruption caused by a fuel supply interruption. My opinion is that HECO's assessment of its LSFO inventory requirement is reasonable. This study recommended inventory level of 34.7 days of average consumption.

Q. HOW DOES THIS INVENTORY LEVEL COMPARE TO ACTUAL HECO INVENTORY LEVELS?

A. HECO maintained an average LSFO inventory level of 37 days from 1999 through 2003. The maximum inventory during this period was 41 days in 2001 and the minimum level was 34 days in 2002.

Q. WHAT WAS THE LSFO FUEL INVENTORY STIPULATED IN THE 1994 HECO RATE CASE?

A. It was a 30-day inventory at average daily consumption.

Q. WHY SHOULD HECO BE ALLOWED TO USE 35 DAYS OF AVERAGE CONSUMPTION FOR LSFO INVENTORY?

A. HECO did not have a good justification for its 30-day inventory in the 1994 case. However, it prepared a fuel oil inventory study for this rate case as suggested by the Consumer Advocate in 1994. The HECO inventory study is reasonable and recommends a LSFO inventory that is comparable (2 days less) to its actual inventory levels in the period 1999 to 2003.

Q. WHAT IS YOUR RECOMMENDATION REGARDING DIESEL OIL INVENTORY?

A. HECO prepared a similar analysis of its diesel fuel inventory requirements as it prepared for LSFO inventory in its Fuel Inventory Study. Because diesel oil is primarily used by peaking generation (reciprocating engine and combustion turbine), the average daily consumption approach is not used. Instead, HECO estimated the number of days of inventory needed for emergency consumption. The HECO proposed level of inventory is equivalent to 8.8 days of emergency consumption, which is equivalent to 21,268 barrels of diesel fuel inventory. This level of inventory is the average of the HECO diesel inventory level from 1999 to 2003. The HECO Fuel Inventory Study recommended 12.6 days of emergency consumption. My recommendation is to accept the 1999 to 2003 average inventory level as proposed by HECO.

Q. HOW IS THE TEST YEAR NORMALIZED FUEL INVENTORY DETERMINED?

A. As shown in Exhibit CA-308, fuel inventory is determined separately for residual fuel oil (also referred to as "LSFO") and diesel oil. The residual fuel oil inventory is determined by using the estimated average daily fuel burn rate for LSFO from the production simulation model results (see Exhibit CA-309, Page 1). The average daily LSFO burn rate, expressed in terms of number of barrels per day (bpd), is then multiplied by the desired number of days of supply (i.e., 35 days; see CA-309, Page 1, Line 3) to arrive at the average quantity of fuel to be maintained in inventory. This average LSFO fuel inventory quantity is then multiplied by test year fuel prices (see Exhibit CA-309, Page 1, Line 4) to arrive at the amount of residual fuel oil inventory to be included in rate base (see Exhibit CA-309, Page 1, Line 5). The diesel fuel inventory is based upon HECO's targeted inventory level including allowance for the new DG diesels anticipated to be installed later this year (see Exhibit CA-IR-137) and HECO's May 2005 diesel oil price.

Q. WHAT WAS THE AVERAGE DAILY BURN RATE UTILIZED FOR PURPOSES OF DETERMINING RESIDUAL FUEL OIL INVENTORY?

A. HECO estimated that its test year burn rates were 22,569 bpd for LSFO (See HECO-409, Page 1, column (a)). The results of my production simulation model estimated that the test year average burn rates would be 22,011 bpd for LSFO.

Q. HOW MANY DAYS SUPPLY WERE UTILIZED TO DETERMINE THE QUANTITY OF LSFO IN INVENTORY FOR RATEMAKING PURPOSES?

A. In its direct testimony filing, HECO utilized a 35-day supply of fuel at the average daily burn rate in inventory for its LSFO (see HECO 409, Page 1, column (a)). As shown on CA-309, Page 1, I utilized the same 35-day supply of LSFO inventory for purposes of determining test year fuel inventory amounts.

Q. WHAT FUEL PRICES WERE USED FOR PURPOSES OF DETERMINING TEST YEAR FUEL INVENTORY AMOUNTS?

A. I used HECO's May 2005 fuel prices, which are significantly higher than the June 2004 fuel prices utilized by HECO in its November 2004 direct testimony filing. It is my understanding that HECO intends to use May 2005 fuel prices with its updated production simulation results to be filed with its rebuttal testimony.

VI. <u>ECA FACTOR AT CURRENT RATES</u>.

Q. DID YOU CALCULATE WHAT THE ECA FACTOR UNDER CURRENT RATES WOULD BE FOR THE ESTIMATED 2005 TEST YEAR BASED ON YOUR ESTIMATED FUEL AND PURCHASED ENERGY PRICES AND RESOURCE MIX?

A. Yes, I did. The calculation of the ECA Factor under current rates based on my production simulation results for the estimated 2005 test year is provided as Exhibit CA-314, Page 1. As shown by that exhibit, the ECA Factor at current rates that corresponds with my test year estimates of fuel and purchase power expenses is 5.789 cents per kWh (see Line 68). The ECA factor is 3.203 cents per kWh greater than the ECA Factor of 2.586 cents per kWh in the Company's November 2004 direct testimony filing. The difference is mostly attributable to the fuel and purchased energy price increases from the May 2004 prices used in the Company's November 2004 direct testimony filing and the May 2005 prices utilized in the Consumer Advocate's direct testimony position.

Q. DID YOU CALCULATE ANY OTHER ECAC RELATED RATES OR CHARGES?

A. Yes. The Company's payment for energy purchase from H-Power and the two as-available resources is at HECO's avoided energy costs payment rate. In order to estimate HECO's 2005 test year payments for the energy estimated to be purchased from these providers, I needed to recalculate HECO's avoided energy costs payment rate in HECO's November 2004 direct testimony filing to reflect the Consumer Advocate's direct testimony filing position. Page 2 of Exhibit CA-314 is the derivation of test year 2005 avoided energy costs payment rates based on the estimated 2005 test year composite fuel cost as determined from my production simulation results and HECO's May 2005 fuel prices. In addition, I also calculated the base energy charge to be included in the ECAC at proposed rates for the Consumer Advocate's direct testimony position. Page 3 of Exhibit CA-314 is the derivation of the base energy charge at proposed rates based on the Company's methodology set forth in CA-IR-358.

Q. ARE THERE ANY PROPOSED MODIFICATIONS TO HECO'S ECAC OTHER THAN THOSE ITEMS ASSOCATED WITH UPDATES TO THE ECAC FOR THE ESTIMATED 2005 TEST YEAR?

A. No. In the last rate case HECO originally proposed to modify the ECAC but subsequently withdrew its proposal after objections by the Consumer Advocate and agreed in the last case to continue to use the ECAC in its current form. HECO's November 2004 direct testimony filing did not include any proposals to modify the current form of the ECAC.

Q. WHAT IS THE NET REVENUE EFFECT OF YOUR RECOMMENDED FUEL AND PURCHASED POWER EXPENSE ADJUSTMENTS COMPARED WITH THE REVENUE ADJUSTMENT FOR THE ECA FACTOR YOU CALCULATED?

A. The synchronization of these items is shown in Exhibit CA-101, Schedule C-4, Page 1 and is a positive pre-tax margin of $2,555,000. However, not all of the fuel and purchase power expenditures included in that exhibit, are included in the ECA factor calculation and therefore, some small differences can be expected to occur. Specifically, fuel handling expenses are not included in the ECA factor fuel price calculation; nor are the purchase power capacity payments, or the Kalaeloa and AES O&M energy payments included in the purchase energy prices for the ECA factor calculation. Removing these items would increase the pre-tax margin from the $2,555,000 shown in Exhibit 101, Schedule C-4 to $3,683,000. Since HECO's ECAC essentially results in a dollar for dollar recovery of HECO's purchased energy payments, this revenue gain is attributable to how HECO's ECAC handles increases in fuel prices. In other words, the higher generation fuel prices (i.e., May 2004 versus May 2005) result in a net revenue gain of $3,683,000 because ECAC revenues increased by $3,683,000 more than HECO's fuel cost that are included in the ECA factor calculation.

Q. HOW COULD THAT HAPPEN?

A. The reason is that the sales heat rate currently in HECO's ECAC (0.011170 Mbtu/kWh) is higher than HECO's test year sales heat rate (0.011072 Mbtu/kWh). Essentially, this difference of 0.000098 Mbtu/kWh or approximately 0.9% results in HECO getting 0.9% more ECAC revenues than HECO incurs in those fuel costs. That's because the current sales heat rate calculation over estimates the amount of fuel consumed by HECO's generating plants by the difference between the ECAC sales heat rate and HECO's test year sales heat rate (i.e., 0.9%).

Q. DOES ANYTHING NEED TO BE DONE ABOUT THIS?

A. Yes. On a prospective basis, the new rates set by this proceeding should include a reduction in the sales heat rate in HECO's ECAC to correspond to HECO's test year sales heat rate, thereby preventing HECO from collecting more revenues than determined to be appropriate in this proceeding. Attempts to recover the prior over-collections, would not be reasonable, however, as such attempts would constitute retro-active ratemaking. It should be noted, however, that HECO may have been able to offset some of its increased in non-fuel related expenditures by this net gain in ECAC revenues due to HECO being able to generate at a lower sales heat rate since its last rate case. Although I haven't investigated how HECO has been able to accomplish this, I suspect it may primarily be due to transmission improvements since HECO's last rate case that reduced HECO's system losses (which as described earlier in my testimony are embedded in the sale heat rate).

VII. POWER FACTOR.

Q. DID YOU REVIEW HECO'S POWER FACTOR ADJUSTMENT IN ITS RETAIL RATE SCHEDULES?

A. Yes. At the direction of the Consumer Advocate, I reviewed the Power Factor Clause included in the following rate schedules:

- J – General Service
- PS – Large Power Secondary
- PP – Large Power Primary
- PT – Large Power Transmission

Exhibit CA-315 titled "Power Factor – The Basics" is a presentation that I've used in the past to explain power factor and the need for power factor provisions in a utility's rate schedules. Although the concept is often difficult to understand, power factor, in summary, is a measure of the customer's reactive power needed to operate the customer inductive loads such as induction motors, certain types of lighting and transformers. Also, there are devices and equipment, such as capacitors that the customer can install to balance out its reactive power needs rather than the utility providing the reactive power to the customer. In fact, almost without exception, the best location to deal with reactive power is at the source; i.e., the customer's equipment creating the need for reactive power. The consequence of the utility supplying the customer's reactive power (rather than the customer installing the equipment to do so itself) is higher utility system losses, installation of capacity banks and the need for more capacity for the system to produce and deliver the reactive power needs of the customer.

Q. HOW IS THE POWER FACTOR USED IN THESE RATE SCHEDULES?

A. The energy and demand charges in each of the rate schedules mentioned previously are decreased or increased by 0.10% for each 1% that the average monthly power factor is above or below 85%.

Q. DO YOU BELIEVE THIS METHOD OF CALCULATION IS REASONABLE?

A. I believe that adjusting the demand and energy charges to reflect the customers power factor is appropriate. However, it is not a common practice to decrease the customer's charges if a certain power factor is achieved.

Q. WHAT IS A COMMON PRACTICE OF APPLYING ADJUSTMENTS FOR POWER FACTOR?

A. A common electric utility industry practice is to charge the customer when its power factor is less than a particular power factor such as 95% lagging.

Q. WHY IS A 95% POWER FACTOR REASONABLE?

A. The electric power system must operate at a 100% power factor. Electric generators provide the reactive power that is consumed by customers. Power factor is the measure of reactive power consumed in relation to real power consumed by the customer. The lower the consumer power factor, the greater amount of reactive power that must be supplied by the electric utility.

Q. WHAT IS A REASONABLE POWER FACTOR FOR THE UTILITY TO SUPPLY?

A. Prudent utility practice is for the electric utility to correct power factor from 95% to 100% using electric generation.

Q. WHAT DO YOU RECOMMEND THAT HECO SHOULD MODIFY IN ITS RATE SCHEDULES?

A. I recommend that HECO increase the customer charges when power factor is less than 95% lagging and that no credits would apply to the customer's charges with regard to power factor.

Q. DO YOU RECOMMEND A PARTICULAR RATE ADJUSTMENT?

A. In the absence of cost of service information specific to power factor, it would be reasonable to increase demand and energy charges to customers 0.1% for each percent that the customer's power factor is less than 95% power factor. This 0.1% adjustment for each percent of power factor less than 95% is the same adjustment as is currently used by HECO. However, the specific adjustment provision should be determined from a cost of service study that calculates the cost of reactive power and subsequently translates that cost into a power factor adjustment.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBITS

OF

JOSEPH A. HERZ

JOSEPH A. HERZ

Mr. Herz is President of Sawvel and Associates, Inc. (Sawvel), a professional consulting firm founded in 1951. He has over 30 years of experience in the areas of public utility planning, financing, operations and management for electric, natural gas, steam, water and wastewater utilities.

He is a registered Professional Engineer. His professional experience includes planning and analytical studies related to electric power supply, transmission arrangements, feasibility studies, economic analyses and rate studies and contract negotiations. He has conducted detailed cost-of-service, rate, financial, power supply and transmission studies involving various investor, municipal and cooperative-owned systems.

Mr. Herz has testified on numerous occasions as an expert witness concerning regulatory matters. He has participated in more than 100 projects involving regulatory proceedings and has testified before 14 state regulatory commissions on electric, gas, steam, and water utility services and the FERC on matters involving electric and gas utilities.

He is experienced in long-range planning for acquisition and/or expansion of utility systems, engineering, financial and economic feasibility investigations and analyses. Power supply experience includes evaluating the technical and financial feasibility of transmission and power supply resources and related arrangements; power pooling, including integration of transmission and generating facilities; and, preparation and negotiation of related power supply and transmission contracts. Mr. Herz has served as an independent arbitrator on power supply contract disputes.

Education

University of Nebraska
B.S., Electrical Engineering, 1971

Registration

Professional Engineer — Indiana and Ohio

Professional Organizations

American Gas Association
American Public Power Association
American Water Works Association
The Institute of Electrical and Electronics Engineers, Inc.
National Society of Professional Engineers
Ohio Society of Professional Engineers

PROJECTS INVOLVING REGULATORY FILINGS
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Utility	Docket No.	Issues and/or Scope	Client	Year
Federal Energy Regulatory Commission				
Westar Energy, Inc.	ER05-925-000	Open Access Transmission Tariff rate revisions for transmission and ancillary services	Kansas Municipal Utilities, Kansas Power Pool, Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities and Kansas Municipal Energy Agency	2005
Westar Energy, Inc. Kansas Gas and Electric Company	ER03-9-002, -003, -004, -005 ER98-2157-002, -003, -004 EL05-64-000	Westar Energy and KGE market power mitigation proposal	Kansas Municipal Utilities and Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities	2005
Kansas City Power & Light Company and Great Plains Power, Inc.	ER99-1005-000 ER02-725-000 EL05-3-000	Ability of KCP&L to exercise market power	Unified Government of Wyandotte County/Kansas City, Kansas, Board of Public Utilities	2005
Dayton Power & Light Company	EL00-24-000	Contract dispute and interpretation of certain pricing provisions	Arcanum, Eldorado, Jackson Center, Lakeview, Mendon, Minster, New Bremen, Tipp City, Waynesfield and Yellow Springs, Ohio	2000
Western Resources and Kansas City Power & Light	EC97-56-000	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
Western Resources and Kansas City Power & Light	ER97-4669-000	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
FirstEnergy Operating Companies	EC97-5-000	IEU/FirstEnergy Merger Intervention and other related relief	Industrial Energy Users of Ohio	1997
FirstEnergy Operating Companies	EC97-413-000	IEU/FirstEnergy Merger Intervention and other related relief	Industrial Energy Users of Ohio	1997

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Utility	Docket No.	Issues and/or Scope	Client	Year
Public Utility District No. 2 of Grant County Washington	EL95-35-000	Determine appropriate allocation of power from Priest Rapids Project	Kootenai Electric Cooperative, Inc., Clearwater Power Company, Idaho County Light & Power Cooperative Association, Inc., and Northern Lights, Inc.	1995
PacifiCorp	ER96-8-000	Transmission, cost of service and rate design	Utah Municipal Power Agency Deseret Generation and Transmission Cooperative, Inc.	1995
Dayton Power & Light Company	ER95-83-000	Transmission power services and rates	Arcanum, Eldorado, Jackson Center, Lakeview, Mendon, Minster, New Bremen, Tipp City, Waynesfield and Yellow Springs, Ohio	1995
Dayton Power & Light Company	94-1469-000	Transmission/interconnection/power services and rates	City of Piqua, Ohio	1994
Cincinnati Gas & Electric Company	ER94-1637-000	Transmission service and rates	City of Hamilton, Ohio	1994
Public Service Company of New Mexico	EL-94-6-000	Fuel inventory practices and expense accounting	Plains Electric Generation and Transmission Cooperative	1994
CINergy (merger of Cincinnati Gas & Electric Company and PSI Energy, Inc.)	ER93-6-000	Transmission issues, cost of service and rate design	City of Hamilton, Ohio	1993
American Electric Power Company	ER93-540-000	Transmission issues, cost of service and rate design	City of Hamilton, Ohio	1993
Ohio Power Company and Kentucky Power Company	ER93-295-001	Transmission loss factors	City of Hamilton, Ohio	1993

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Utility	Docket No.	Issues and/or Scope	Client	Year
PacifiCorp Electric Operations	ER93-675-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1993
PacifiCorp Electric Operations	ER91-494-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1991
PacifiCorp Electric Operations	ER91-471-0000	Transmission issues, cost of service and rate design	Utah Municipal Power Agency	1991
Ohio Power Company	EL91-1-000 and EL90-42-000	Interconnected utility operations and scheduling matters	City of Hamilton, Ohio	1990
Arizona Public Service Company	ER89-265-000	Transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1989
Cincinnati Gas & Electric Company	ER89-17-000 and ER89-19-000	Transmission service, schedule restrictions and billing for transmission service	City of Hamilton, Ohio	1989
Utah Power and Light Company	EL85-12	PURPA wheeling under Sections 210, 211 and 212 of the Federal Power Act	Utah Municipal Power Agency and City of Manti, Utah	1985
Utah Power and Light Company	ER84-571/572	Transmission issues, cost of service and rate design	Utah Municipal Power Agency and the Cities of Manti and Provo, Utah	1985
Northern Indiana Public Service Company	ER83-396-000	Transmission issues, price squeeze, cost of service and rate design	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Walkerton and Winamac, Indiana	1983
Utah Power and Light Company	ER83-427-000	Transmission issues, revenue requirement, cost of service and rate design	Manti, Utah	1983
Ohio Power Company	ER82-553-000	Engineering issues, cost of service and rate design	Ohio Power Municipals	1982

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Utility	Docket No.	Issues and/or Scope	Client	Year
Arizona Public Service Company	ER82-481-000	Transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1982
Arizona Public Service Company	ER81-179-000	Wholesale and transmission issues, cost of service and rate design	Plains Electric Generation and Transmission Cooperative	1981
Public Service Company of New Mexico	ER80-313	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Public Service Company of New Mexico	ER79-478/479	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Public Service Company of New Mexico	ER78-337/338	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Northern Indiana Public Service Company	ER78-509	Price squeeze and rate design	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Walkerton and Winamac, Indiana	1979
Federal Power Commission:				
Ohio Edison Company	E-9497	Engineering issues, cost of service	The Wholesale Consumers of Ohio Edison Company	1976
Colorado Public Utilities Commission:				
Public Service Company of Colorado	1425 Phase II	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1981
Florida Public Service Commission:				

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Utility	Docket No.	Issues and/or Scope	Client	Year
Gulf Power	010949-EI	Engineering and cost of service issues that have an actual or potential impact on the FEA	The Executive Agencies of the United States	2001
Florida Power Corporation	80119-EU	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Hawaii Public Utilities Commission:				
Hawaiian Electric Company, Inc.	04-0113	Evaluation of application for an increase in rates using a 2005 test year, cost of service and rate design issues	Division of Consumer Advocacy, State of Hawaii	2004
Commission Initiated Generic Investigation	03-0371	Commission initiated generic investigation of distributed generation in Hawaii	Division of Consumer Advocacy, State of Hawaii	2004
Kauai Electric Division	01-0005	Avoided energy costs associated with an Energy Purchase Agreement with Kauai Winds Inc. and inclusion in ERAC	Division of Consumer Advocacy, State of Hawaii	2001
Hawaii Electric Light Company, Inc.	99-0355	Transmission system improvements with IPP purchase power addition	Division of Consumer Advocacy, State of Hawaii	2000
Hawaii Electric Light Company, Inc.	99-0207	Generation and purchase power, operation and maintenance expenses, system losses and engineering issues	Division of Consumer Advocacy, State of Hawaii	2000
Hawaii Electric Light Company, Inc.	99-0346	Need for capacity additions/review of IPP Purchase Power Agreement	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc.	98-0013	Need for capacity resource additions, IPP purchase power agreement	Division of Consumer Advocacy, State of Hawaii	1999

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Utility	Docket No.	Issues and/or Scope	Client	Year
Hawaii Electric Light Company, Inc	97-0420	Generation and purchase power, operation and maintenance expenses, system losses and engineering issues	Division of Consumer Advocacy, State of Hawaii	1999
Hawaii Electric Light Company, Inc	97-0349	Integrated resource planning	Division of Consumer Advocacy, State of Hawaii	1999
Kauai Electric Division	KE94-0097	Engineering issues, generation and purchase power, operation and maintenance expenses, system losses and cost of service and rate design	Division of Consumer Advocacy, State of Hawaii	1994
Hawaiian Electric Company, Inc.	7766	Engineering issues, generation and purchase power, operation and maintenance expenses, system losses and cost of service and rate design	Division of Consumer Advocacy, State of Hawaii	1994
Hawaii Electric Light Company, Inc.	7623	Need for capacity resource additions and purchase power contracts	Division of Consumer Advocacy, State of Hawaii	1994
Hawaii Electric Light Company, Inc.	7764	Engineering issues, generation and purchase power, operation and maintenance expenses and system losses	Division of Consumer Advocacy, State of Hawaii	1994
Indiana Public Service Commission				
Wayne County Rural Electric Membership Cooperative	39048	Engineering issues, cost of service and rate design	Wayne County Rural Electric Membership Cooperative	1990
New Carlisle, Indiana	Unknown	Engineering issues, revenue requirements, cost of service and rate design	New Carlisle, Indiana	1975

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Utility	Docket No.	Issues and/or Scope	Client	Year
Kansas Corporation Commission:				
Western Resources and Kansas City Power & Light	97-WSRE-676-MER	Western Resources Merger Intervention and other related relief	Kansas City, Kansas Board of Public Utilities	1999
Kansas Gas and Electric Company	142-098-U	Engineering issues, cost of service and rate design	McConnell Air Force Base	1985
Michigan Public Service Commission:				
Detroit Thermal	Case No. U-13691	Implement initial default tariff rates for steam service	Detroit Thermal	2004
Michigan Consolidated Gas Company	Case No. U-7895	Engineering issues, cost of service and rate design	Traverse City Light and Power Board	1984
Indiana and Michigan Electric Company	Case No. U-7791	Engineering issues, cost of service and rate design	Auto Specialties, Southern Michigan Cold Storage, Watervliet Paper Company, and Whirlpool Corporation	1984
Detroit Edison Company	Case No. U-7232	Interconnection agreements and power sales contract	Michigan Attorney General	1983
Consumers Power Company	Case No. U-6923	Cost of service, rate design and price elasticity	Clark Equipment Company	1982
Indiana and Michigan Electric Company	Case No. U-6927	Engineering issues, cost of service and rate design	Auto Specialties, Clark Equipment Company, and Whirlpool Corporation	1981
Upper Peninsula Power Company	Case No. U-6785	Engineering issues, cost of service and rate design	Michigan Technological University	1981

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Utility	Docket No.	Issues and/or Scope	Client	Year
Upper Peninsula Power Company	Case No. U-6485	Engineering issues, cost of service and rate design	Michigan Technological University	1980
Indiana and Michigan Electric Company	Case No. U-6148	Engineering issues, cost of service and rate design	Auto Specialties, Clark Equipment Company, and Whirlpool Corporation	1980
Missouri Public Service Commission:				
Kansas City Power and Light Company	Case No. ER83-49	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Kansas City Power and Light Company	Case No. EO-78-161	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1980
Montana Public Service Commission:				
Malmstrom Air Force Base	D2001.10.144	Rate design for customers receiving default power supply and transmission services, and limitations on the ability of qualified customers to return to the default supply services	The Executive Agencies of the United States	2001
New Mexico Service Commission:				
Public Service Company of New Mexico	Case No. 03-00352-UT	Appropriateness of underground projects rate rider	Rio Rancho, New Mexico	2004
Otero Electric Cooperative	Case No. 2048	Demand metering and rate design	Otero Electric Cooperative	1987
Gas Company of New Mexico	Case No. 1875	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1984

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Utility	Docket No.	Issues and/or Scope	Client	Year
Gas Company of New Mexico	Case No. 1787	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Gas Company of New Mexico	Case No. 1710	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1982
Gas Company of New Mexico	Case No. 1568	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1982
Ohio Public Utilities Commission:				
FirstEnergy Operating Companies	Case No. 98-1636-EL-UNC	Transmission system reliability - sale and transfer of generating assets	Industrial Energy Users of Ohio	1999
Ohio Edison Company	Case No. 93-1048-EL-CSS	Cost of service and predatory pricing	Youngstown Thermal, Limited Partnership	1994
Cincinnati Gas & Electric Company	Case No. 87-593-GA-CSS	Metering and billing dispute	Sheraton/Springdale Hotel	1987
Dayton Power and Light Company	Case No. 82-517-EL-AIR	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1983
Dayton Power and Light Company	Case No. 81-1256-EL-AIR	Revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1982
Dayton Power and Light Company	Case No. 81-1237-EL-CSS	Billing procedures and practices	The Dayton Tire and Rubber Company	1982
Toledo Edison Company	Case No. 81-620-EL-AIR	Determination of billing units and rate design	Seaway Food Town, Inc.	1982
Ohio American Water Company	Case Nos. 81-385-WW-AIR and 81-739-WW-CMR	Engineering issues, cost of service and rate design	City of Tiffin, Ohio	1982

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Utility	Docket No.	Issues and/or Scope	Client	Year
Dayton Power and Light Company	Case No. 81-21-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1981
Dayton Power and Light Company	Case No. 80-687-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1981
Ohio American Water Company	Case No. 79-3143-WW-AIR	Engineering issues, revenue requirements, cost of service and rate design	Cities of Marion and Tiffin, Ohio	1980
Dayton Power and Light Company	Case No. 79-510-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1980
Cincinnati Gas & Electric Company	Case No. 79-11-EL-AIR	Cost of service and rate design	The Ohio Council of Retail Merchants	1979
Columbus and Southern Ohio Electric Company	Case No. 78-1438-EL-AIR	Cost of service and rate design	The Ohio Council of Retail Merchants	1979
Seneca Utilities, Inc.	Case No. 78-287-WW-AIR	Engineering issues, revenue requirements, cost of service and rate design	Lake Seneca Property Owners Association	1979
Dayton Power and Light Company	Case No. 78-92-EL-AIR	Engineering issues, revenue requirements, cost of service and rate design	The Executive Agencies of the United States	1979
Texas Public Utility Commission:				
Houston Lighting & Power Company	5779	Engineering issues, cost of service and rate design	The Executive Agencies of the United States	1984

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Utility	Docket No.	Issues and/or Scope	Client	Year
Utah Public Service Commission:				
Hill Air Force Base	01-035-01	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-23	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-35	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Hill Air Force Base	01-035-36	Evaluate power cost adjustment mechanism to determine if it is non-discriminatory, accurately reflects the actual cost of providing the service, and is necessary under the circumstances	The Executive Agencies of the United States	2001
Hill Air Force Base	00-035-15	Revenue requirements, cost of service, rate design	The Executive Agencies of the United States	2001
Wisconsin Public Service Commission:				
Barron Electric Cooperative	Case No. 380-EI-1	Transmission wheeling charges	Barron Electric Cooperative	1982
Wyoming Public Service Commission:				
PacifiCorp	20000-ER-95-99	Revenue requirements, cost of service, rate design and jurisdictional allocations	Marathon Oil Company	1996

Hawaiian Electric Company, Inc.

COMPARISON OF TEST YEAR ESTIMATES FOR FUEL EXPENSE, PURCHASE POWER EXPENSE, EFFICIENCY FACTOR (SALES HEAT RATE) AND FUEL INVENTORY

Estimated Twelve Months Ending December 31, 2005

				Production Simulation Results using HECO DT Inputs			
Line	Description	CA Reference	Units	HECO DT Filing (a)	CA Output Results (b)	CA DT Position (c)	CA Adjustments to HECO DT Filing (c -a) (d)
	FUEL EXPENSE						
1.	Fuel Oil Expense	CA-304, Page 1	$000s	$ 287,531	$ 287,871	$ 444,934	$ 157,403
2.	Fuel Related Expense	CA-305, Page 1	$000s	$ 5,173	$ 5,687	$ 4,709	$ (464)
3.	Total Fuel Expense		$000s	$ 292,704	$ 293,558	$ 449,643	$ 156,939
	PURCHASED POWER EXPENSE						
4.	Energy Payments	CA-312, Page 1	$000s	$ 189,943	$ 188,982	$ 260,048	$ 70,105
5.	Firm Capacity Payments	CA-313, Page 1	$000s	$ 108,621	$ 108,295	$ 108,293	$ (328)
6.	Total Purchased Power Expense		$000s	$ 298,564	$ 297,276	$ 368,341	$ 69,777
	GENERATION EFFICIENCY FACTOR						
7.	Sales Heat Rate	CA-306, Page 1	MMBTU/kWh Sales	0.011077	0.010982	0.011072	(0.000005)
8.	FUEL INVENTORY	CA-308, Page 1	$000s	$ 28,742	$ 28,279	$ 43,701	$ 14,959
	ENERGY COST ADJUSTMENT CLAUSE						
9.	ECA Factor at Current Rates	CA-314, Page 1	¢/kWh	2.586	N/A	5.789	3.203
10.	Base Fuel Energy Charge at Proposed Rates	CA-314, Page 3	¢/kWh	6.0520	N/A	16.0006	9.9486

Note: Totals may not add exactly due to rounding.

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Hawaiian Electric Company, Inc.

ANTICIPATED HECO UPDATES AND CA MODIFICATIONS TO THE PRODUCTION SIMULATION INPUTS USED IN HECO'S DT FILING

Line	Description	CA Reference	Units, where Applicable	HECO DT Filing Inputs to be updated/modified (a)	Anticipated HECO Updates to HECO DT Inputs (b)	CA DT Modifications to HECO DT Inputs (c)
	ENERGY REQUIREMENTS					
1.	Forecasted Sales	HECO-403/HECO May 2005 Update	GWh	7,842.8	7,856.0	7,856.0
2.	Company Use	HECO-WP-403, Page 1/CA-IR-153	GWh (basis)	16.6 (% of Sales)	16.7 (% of Sales)	15.5 (5 Yr Avg)
3.	Losses	HECO-WP-403, Page 2/CA-IR-153	% (basis)	4.70%	4.70%	4.65% (5 Yr Avg)
	FUEL PRICE					
4.	Based on Actual Contract Price for:	HECO-402/HECO May 2005 Update		May, 2004	May, 2005	May, 2005
5.	Low Sulfur Fuel Oil	HECO-402/HECO May 2005 Update	$/BBL	34.7257	53.7346	53.7346
6.	Diesel	HECO-402/HECO May 2005 Update	$/BBL	56.8000	79.4392	79.4392
	CHP - DG DIESEL ASSUMPTIONS					
7.	CHP Included ?	HECO-409, Page 6		Yes	No	No
8.	DG Diesels Included ? (If Yes, Mo.s Operated)	HECO May 2005 Update, Attch 1A		No	Yes (July-Oct)	Yes (Oct)
	GENERATING UNIT RELATED CHARACTERISTICS					
9.	Calibration Factor	HECO-WP-404, Page1/HECO May 2005 Update		CY 2003	CY2004	Avg-'03/'04
10.	Equivalent Forced Outage Rate	HECO-WP-406, Page 3/CA-IR-461		5 Yr Avg ('99-'03)	Revised, see CA-IR-461	5 Yr Avg ('99-'03)
11.	Planned/Maintenance Outage Schedule	CA-WP-306, Pages 4-6		CA-IR-46	CA-IR-43 (Revised)	CA-IR-46
12.	Heat Rate - ABC Coefficients	CA-WP-306, Pages 2, 3		CA-IR-501	CA-IR-128 (Revised)	CA-IR-128 (Revised)
	PURCHASED POWER ASSUMPTIONS					
13.	Kalaeloa - GNPIPD	HECO May 2005 Update, Attch 3	MWh	108.409	109.099	109.099
14.	LSFO Fuel Price	HECO May 2005 Update, Attch 3	$/BBL	36.280	51.802	51.802
15.	AES - GNPIPD - 3Q	HECO May 2005 Update, Attch 3		107.864	108.479	108.479
16.	- 1Q	HECO May 2005 Update, Attch 3		108.958	109.642	109.642
17.	Availability - February days	HECO May 2005 Update, Attch 3		29	28	28
18.	- Actual kWh (bonus calc)	HECO May 2005 Update, Attch 3		thru 6/04	thru 4/05	thru 6/04 (info not provided)
	FUEL RELATED EXPENSE					
19.	Fuel Handling	HECO-WP-410/CA-IR-276	$000	$ 4,554	$ 3,882	$ 3,882
20.	Trucking Costs (Honolulu Plant)	HECO-WP-410/CA-IR-276	$/BBL	3.75	2.9053	2.9053
	FUEL INVENTORY					
21.	Central Station Inventory	HECO-411/HECO May 2005 Update, Attch 7		5 Yr Avg ('99-'03)	5 Yr Avg ('00-'04)	5 Yr Avg ('00-'04)
22.	DG Diesel	HECO May 2005 Update, Attch 7	BBL	N/A	N/A	500

Hawaiian Electric Company, Inc.

MAY 2005 FUEL PRICES FOR 2005 TEST YEAR
WEIGHTED AVERAGE FUEL PRICES

Line	LSFO	Chevron	Tesoro	Total (c) = (a)+(b)		
		(a)	(b)	(c)		
1.	Test Year Percent of Purchases	61.34%	38.66%	100.00%		
2.	Price per Barrel ($/Barrel)	$53.4192	$54.2351			
3.	Weighted Average % * Barrel (Line 1 * Line 2)	$32.7673	$20.9673	$53.7346		
4.	Diesel	$79.4392		$79.4392		
		LSFO Honolulu	LSFO Kahe	LSFO Waiau	Diesel	DG Diesel
		(d)	(e)	(f)	(g)	(h)
5.	Fuel Price	$53.7346	$53.7346	$53.7346	$79.4392	$79.4392
6.	Thruput	$2.9053	-	-	-	$1.3524
7.	Total $/Barrel	$56.6399	$53.7346	$53.7346	$79.4392	$80.7916
8.	Petrospect Cost	$0.0124	$0.0124	$0.0124	$0.0555	$0.0555
9.	Grand Total $/Barrel	$56.6523	$53.7470	$53.7470	$79.4947	$80.8471

Source: HECO May 2005 Update

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Hawaiian Electric Company, Inc.

ESTIMATED 2005 TEST YEAR GENERATION (GWh)

Line	Description	CA Reference	HECO DT Filing	CA Output Using HECO DT Filing Inputs	Anticipated HECO May 2005 Update RT Filing	CA DT Position
			(a)	(b)	(c)	(d)
1.	Sales	HECO May 2005 Update	7,842.8	7,842.8	7,856.0	7,856.0
2.	Company Use	2000-04 Avg., CA-IR-153	16.6	16.6	16.7	15.5
3.	Sales + NC		7,859.4	7,859.4	7,872.7	7,871.5
4.	Losses	2000-04 Avg., CA-IR-153	387.6	387.6	388.3	383.9
5.	Net System Input		8,247.0	8,247.0	8,260.9	8,255.3
6.	Purchase Power	CA-309, Pages 3 and 5	3,381.0	3,368.1	N/A	3,413.3
7.	Net HECO		4,866.0	4,878.9	N/A	4,842.0
7a.	Central Station	CA-309, Pages 2 and 4	4,854.8	4,867.0	N/A	4,837.9
7b.	CHP -DG Diesel at System Level	CA-309, Pages 3 and 5	11.2	11.7	N/A	1.5
7c.	Difference		0.0	0.2	N/A	2.7

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Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Contract Fuel Prices)

		HECO DT Filing			CA Output Using HECO DT Filing Inputs			CA DT Position		
Line	LSFO/Diesel	Fuel Consumption (Barrels)	Contract Prices ($/bbl)	Fuel Expense ($000) (a) x (b)	Fuel Consumption (Barrels)	Contract Prices ($/bbl)	Fuel Expense ($000) (d) x (e)	Fuel Consumption (Barrels)	Contract Prices ($/bbl)	Fuel Expense ($000) (g) x (h)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1.	Honolulu	132,246	34.7257	4,592	267,979	34.7257	9,306	246,884	53.7346	13,266
2.	Kahe	5,651,161	34.7257	196,241	5,767,742	34.7257	200,289	5,850,761	53.7346	314,388
3.	Waiau-Steam	2,454,220	34.7257	85,225	2,085,557	34.7257	72,422	2,040,333	53.7346	109,637
4.	Subtotal	8,237,627		286,057	8,121,278		282,017	8,137,978		437,291
5.	Waiau-Diesel	11,188	56.8000	635	86,852	56.8000	4,933	93,730	79.4392	7,446
6.	Subtotal	11,188		635	86,852		4,933	93,730		7,446
7.	Central Station Total	8,248,815		286,693	8,208,130		286,950	8,231,708		444,737
8.	CHP-DG Diesel	14,753	56.8000	838	16,209	56.8000	921	2,480	79.4392	197
9.	Grand Total	8,263,568		287,531	8,224,340		287,871	8,234,188		444,934
		Composite Fuel Price ($/bbl)		34.7950			35.0023			54.0350

Note: Totals may not add exactly due to rounding.

Sources: HECO-404, Page 1; Columns (a), (b), and (e)
CA-309, Page 2; Column (d)
CA-309, Page 4; Column (g)
CA-302, Page 1: Column (h)

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Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Including Trucking and Petrospect Costs)

		HECO DT Filing			CA Output Using HECO DT Inputs			CA DT Position		
Line	LSFO/Diesel	Fuel Consumption (Barrels)	Fuel Costs ($/bbl)	Fuel Expense ($000) (a) x (b)	Fuel Consumption (Barrels)	Fuel Costs ($/bbl)	Fuel Expense ($000) (d) x (e)	Fuel Consumption (Barrels)	Fuel Costs ($/bbl)	Fuel Expense ($000) (g) x (h)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1.	Honolulu	132,246	38.4881	5,090	267,979	38.4881	10,314	246,884	56.6523	13,987
2.	Kahe	5,651,161	34.7381	196,311	5,767,742	34.7381	200,360	5,850,761	53.7470	314,461
3.	Waiau-Steam	2,454,220	34.7381	85,255	2,085,557	34.7381	72,448	2,040,333	53.7470	109,662
4.	Subtotal	8,237,627		286,655	8,121,278		283,123	8,137,978		438,109
5.	Waiau-Diesel	11,188	56.8555	636	86,852	56.8555	4,938	93,730	79.4947	7,451
6.	Subtotal	11,188		636	86,852		4,938	93,730		7,451
7.	Central Station Total	8,248,815		287,292	8,208,130		288,061	8,231,708		445,560
8.	CHP-DG Diesel	14,753	58.2079	859	16,209	58.2079	944	2,480	80.8471	201
9.	Grand Total	8,263,568		288,150	8,224,340		289,004	8,234,188		445,761
	Composite Fuel Price ($/bbl)			34.8700			35.1401			54.1354

Note: Totals may not add exactly due to rounding.

Sources: HECO-404, Page 2; Columns (a), (b), and (e)
CA-309, Page 3; Column (d)
CA-309, Page 5; Column (g)
CA-302, Page 1: Column (h)

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Hawaiian Electric Company, Inc.

ESTIMATED 2005 TEST YEAR FUEL RELATED EXPENSES

Line	Description	CA Reference	HECO DT Filing ($000) (a)	CA Output Using HECO DT Inputs ($000) (b)	CA DT Position ($000) (c)
1.	**Fuel Handling Expenses**	HECO-WP-410, CA-IR-276	$ 4,554	$ 4,554	$ 3,882
2.	**Fuel Trucking Expenses**	CA-305, Page 2	$ 516	$ 1,027	$ 721
3.	**Petrospect Expenses**	CA-305, Page 3	$ 103	$ 106	$ 106
4.	**Total**		$ 5,173	$ 5,687	$ 4,709

Note: Totals may not add exactly due to rounding.

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Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Trucking Costs)

		HECO DT Filing			CA Output Using HECO DT Inputs			CA DT Position		
Line	LSFO/Diesel	Fuel Consumption (Barrels)	Trucking Cost ($/bbl)	Fuel Expense ($000) (a) x (b)	Fuel Consumption (Barrels)	Trucking Cost ($/bbl)	Fuel Expense ($000) (d) x (e)	Fuel Consumption (Barrels)	Trucking Cost ($/bbl)	Fuel Expense ($000) (g) x (h)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1.	Honolulu	132,246	3.7500	496	267,979	3.7500	1,005	246,884	2.9053	717
2.	Kahe	5,651,161	-	-	5,767,742	-	-	5,850,761	-	-
3.	Waiau-Steam	2,454,220	-	-	2,085,557	-	-	2,040,333	-	-
4.	Subtotal	8,237,627		496	8,121,278		1,005	8,137,978		717
5.	Waiau-Diesel	11,188	-	-	86,852	-	-	93,730	-	-
6.	Subtotal	11,188			86,852			93,730		
7.	Central Station Total	8,248,815		496	8,208,130		1,005	8,231,708		717
8.	CHP-DG Diesel	14,753	1.3524	20	16,209	1.3524	22	2,480	1.3524	3
9.	Grand Total	8,263,568		516	8,224,340		1,027	8,234,188		721

Note: Totals may not add exactly due to rounding.

Source: HECO-405, Page 2; Columns (a), (b) and (e)
CA-309, Page 2; Column (d)
CA-309, Page 4; Column (g)
HECO May 2005 Update; Column (h)

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Hawaiian Electric Company, Inc.

DERIVATION OF FUEL EXPENSE
(Petrospect Costs)

		HECO DT Filing			CA Output Using HECO DT Inputs			CA DT Position		
Line	LSFO/Diesel	Fuel Consumption (Barrels) (a)	Petrospect Cost ($/bbl) (b)	Fuel Expense ($000) (a) x (b) (c)	Fuel Consumption (Barrels) (d)	Petrospect Cost ($/bbl) (e)	Fuel Expense ($000) (d) x (e) (f)	Fuel Consumption (Barrels) (g)	Petrospect Cost ($/bbl) (h)	Fuel Expense ($000) (g) x (h) (i)
1.	Honolulu	132,246	0.0124	2	267,979	0.0124	3	246,884	0.0124	3
2.	Kahe	5,651,161	0.0124	70	5,767,742	0.0124	72	5,850,761	0.0124	73
3.	Waiau-Steam	2,454,220	0.0124	30	2,085,557	0.0124	26	2,040,333	0.0124	25
4.	Subtotal	8,237,627		102	8,121,278		101	8,137,978		101
5.	Waiau-Diesel	11,188	0.0555	1	86,852	0.0555	5	93,730	0.0555	5
6.	Subtotal	11,188		1	86,852		5	93,730		5
7.	Central Station Total	8,248,815		103	8,208,130		106	8,231,708		106
8.	CHP-DG Diesel	14,753	0.0555	1	16,209	0.0555	1	2,480	0.0555	0
9.	Grand Total	8,263,568		104	8,224,340		106	8,234,188		106

Note: Totals may not add exactly due to rounding.

Source: HECO-405, Page 3; Columns (a), (b), (e) and (g)
CA-309, Page 3; Column (d)
CA-309, Page 5; Column (g)

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Hawaiian Electric Company, Inc.

TEST YEAR FUEL EFFICIENCY

Line	Description	HECO DT Filing (a)	CA Output Using HECO DT Inputs (b)	CA DT Position (c)
	ENERGY (Net GWh)			
1.	**Company Generated Energy**	4,866.0	4,878.7	4,839.3
2.	**Central Station Generated Energy**	4,854.8	4,867.0	4,837.9
3.	**Steam Generated Energy**	4,851.9	4,850.8	4,821.0
4.	**CT Generated Energy**	2.8	16.2	16.8
5.	**CHP - DG Diesel Generated Energy**	11.2	11.7	1.5
6.	**Test Year Sales**	7,842.8	7,842.8	7,856.0
	FUEL CONSUMPTION (Mbtu)			
7.	**Total Fuel Consumed**	51,225,298	50,955,866	51,019,252
8.	**Central Station Fuel Consumed**	51,138,847	50,860,879	51,004,719
9.	**Steam Fuel Consumed**	51,073,288	50,351,926	50,455,463
10.	**CT Fuel Consumed**	65,559	508,953	549,255
11.	**CHP - DG Diesel Fuel Consumed**	86,451	94,988	14,533
	HEAT RATE (Btu/kWh)			
12.	**Total Heat Rate**	10,527	10,444	10,543
13.	**Central Station Heat Rate**	10,534	10,450	10,543
14.	**Steam Heat Rate**	10,526	10,380	10,466
15.	**CT Heat Rate**	23,068	31,401	32,683
16.	**CHP - DG Diesel Heat Rate**	7,713	8,093	9,833
17.	**HECO Central Station and DG Diesel Generation of Net System Input (Percent)**	59.00%	59.16%	58.65%
18.	**Central Station Generation of Net System Input**	58.87%	59.02%	58.64%
19.	**CHP-DG Diesel Generation of Net System Input**	0.14%	0.14%	0.02%
20.	**Sales Heat Rate - Central Station (Mbtu/kWh sales)**	0.011077	0.010982	0.011072

Sources: HECO-406; Column (a)
CA-303, CA-309; Columns (b) and (c)

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Hawaiian Electric Company, Inc.

HISTORICAL AND ESTIMATED 2005 TEST YEAR
FUEL EFFICIENCY
(BTU/kWh)

Line	Description	1999	2000	2001	2002	2003	2004	HECO DT Filing	CA Output Using HECO DT Filing Inputs	CA DT Position
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(I)
1.	**Central Station Steam**	10,471	10,463	10,387	10,414	10,413	10540	10,526	10,380	10,466
2.	**Percent Increase**		-0.1%	-0.7%	0.3%	0.0%	1.2%	-0.1%	-1.4%	0.8%
3.	**Central Station Diesel**	44,075	32,918	29,053	21,106	21,081	21327	23,068	31,401	32,683
4.	**Percent Increase**		-25.3%	-11.7%	-27.4%	-0.1%	1.2%	8.2%	36.1%	4.1%
5.	**Central Station Average**	10,494	10,482	10,406	10,436	10,452	10,621	10,534	10,450	10,543
6.	**Percent Increase**		-0.1%	-0.7%	0.3%	0.2%	1.6%	-0.8%	-0.8%	0.9%
7.	**CHP - DG Diesel**							7,713	8,093	9,833
8.	**Percent Increase**							N/A		

Sources: HECO-407; 1999 - 2003
CA-IR-142; 2004
CA-306; Columns (g), (h), (I)

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Hawaiian Electric Company, Inc.

TEST YEAR FUEL OIL INVENTORY

Line	Description	HECO DT Filing			CA Output Using HECO DT Filing Inputs			CA DT Filing		
		Average (Barrels)	Price Per Barrel	Fuel Oil Inventory ($000) (a) x (b)	Average (Barrels)	Price Per Barrel	Fuel Oil Inventory ($000) (d) x (e)	Average (Barrels)	Price Per Barrel	Fuel Oil Inventory ($000) (g) x (h)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1.	Residual Fuel Oil	789,909	34.7983	$ 27,487	778,753	34.7257	$ 27,043	780,354	53.7346	$ 41,932
2.	Diesel Oil	21,768	57.6246	$ 1,254	21,768	56.8000	$ 1,236	22,268	79.4392	$ 1,769
3.	TOTAL INVENTORY	811,677		$ 28,742	800,521		$ 28,279	802,622		$ 43,701

Note: Totals may not add exactly due to rounding.

Sources: HECO-408, Page 1
CA-309, Page 1
CA-311, Page 1
CA-304, Page 1

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Hawaiian Electric Company, Inc.

DERIVATION OF RESIDUAL FUEL OIL INVENTORY

Line	Description	CA Reference	Units	HECO DT Filing (a)	CA Output Using HECO DT Inputs (b)	CA DT Position (c)
1.	**Forecast Residual Fuel Oil Consumption**	CA-304, Page 1	Barrels	8,237,627	8,121,278	8,137,978
2.	**Burn Rate**	Line 1 / 365 days	Barrels/Day	22,569	22,250	22,296
3.	**35 Day Inventory**	Line 2 x 35 days	Barrels	789,909	778,753	780,354
4.	**Fuel Price**	CA-304, Page 1	$/Barrel	$34.7983	$34.7257	$53.7346
5.	**Residual Fuel Oil Inventory**	Line 3 x Line 4	$000	$27,487	$27,043	$41,932

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CA Production Simulation Results Using HECO Direct Testimony Filing Inputs

HECO Fuel Consumption and Generation - Excluding CHP
Sales and Peak Forecast dated June 2004
Maintenance Schedule dated January 12, 2004
Fuel Prices from June 2004 Sales and Peak Forecast

	Fuel Consumption (Mbtu)					MWh Generation					
Month	Kahe	Waiau	Honolulu	Diesel	Total	Kahe	Waiau	Honolulu	Diesel	Total	Net Heat Rate
Jan	2,512,646	1,095,045	150,996	26,661	3,785,348	248,963	104,466	11,654	1,000	366,083	10,340
Feb	2,340,257	927,119	92,088	4,631	3,364,095	230,870	88,325	7,172	189	326,556	10,302
Mar	3,042,119	1,161,304	159,494	36,466	4,399,383	301,226	110,283	12,325	1,397	425,230	10,346
Apr	3,024,090	1,111,335	217,353	122,868	4,475,646	299,529	103,777	16,717	4,380	424,402	10,546
May	2,823,103	1,014,297	182,229	40,731	4,060,361	277,722	96,626	14,021	1,347	389,715	10,419
Jun	2,802,455	1,119,179	217,031	35,300	4,173,965	276,071	105,875	16,700	1,167	399,814	10,440
Jul	3,045,344	1,125,537	124,434	31,522	4,326,837	301,436	106,971	9,722	1,099	419,227	10,321
Aug	3,025,142	1,234,112	248,808	75,329	4,583,391	300,362	116,470	19,082	2,760	438,673	10,448
Sep	3,377,577	1,176,061	170,990	32,643	4,757,272	335,688	111,973	13,131	1,219	462,011	10,297
Oct	3,370,577	1,017,351	89,630	2,987	4,480,545	332,920	97,288	7,034	99	437,340	10,245
Nov	2,991,388	974,418	61,670	24,183	4,051,658	295,529	93,381	4,824	837	394,571	10,269
Dec	3,188,489	707,502	26,860	19,847	3,942,697	313,669	66,899	2,098	715	383,381	10,284
Total	35,543,187	12,663,259	1,741,584	453,168	50,401,198	3,513,984	1,202,332	134,479	16,208	4,867,004	10,450
Calibration Factor - '03	1.0061	1.0211	0.9540	1.1231	1.0091						
Adjusted Total	35,760,001	12,930,454	1,661,471	508,953	50,860,879						
										GWh	
						Steam Generated Energy				4,850.8	10,380
Heat Content (Mbtu/Barrel)	6.20	6.20	6.20	5.86		CT Generated Energy				16.2	31,401
Barrels	5,767,742	2,085,557	267,979	86,852		Central Station Generated Energy				4,867.0	

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CA Production Simulation Results Using HECO Direct Testimony Filing Inputs

Purchased Power and CHP Fuel Consumption and Generation
Sales and Peak Forecast dated June 2004
Maintenance Schedule dated January 12, 2004
Fuel Prices from June 2004 Sales and Peak Forecast

	Fuel Consumption (Mbtu)						MWh Generation					
Month	**AES**	**Kalaeloa**	**H-Power**	**Non-Firm**	**CHP**	**Total**	**AES**	**Kalaeloa**	**H-Power**	**Non-Firm**	**CHP**	**Total**
Jan	2,297,956	1,150,238	260,647	0	615	3,709,455	132,581	134,064	30,802	594	76	298,117
Feb	2,075,573	1,039,107	235,421	0	558	3,350,659	119,750	120,856	27,821	536	69	269,032
Mar	2,297,956	838,291	139,200	0	615	3,276,061	132,581	97,853	16,450	594	76	247,553
Apr	2,223,828	624,320	237,291	0	599	3,086,039	128,304	73,100	28,042	575	74	230,095
May	2,297,956	1,154,001	260,647	0	2,752	3,715,354	132,581	134,377	30,802	594	340	298,694
Jun	2,223,828	1,126,536	252,235	0	2,663	3,605,262	128,304	131,387	29,808	575	329	290,403
Jul	2,297,956	1,148,660	260,647	0	2,752	3,710,014	132,581	134,256	30,802	594	340	298,573
Aug	2,297,956	1,163,466	260,647	0	8,231	3,730,299	132,581	135,944	30,802	594	1,017	300,938
Sep	1,677,632	1,134,311	252,235	0	10,909	3,075,087	95,248	132,606	29,808	575	1,348	259,585
Oct	2,297,956	1,136,803	249,434	0	14,308	3,698,502	132,581	132,943	29,477	594	1,768	297,363
Nov	2,223,828	1,131,308	233,551	0	22,086	3,610,773	128,304	132,307	27,600	575	2,729	291,515
Dec	2,297,956	1,143,629	234,482	0	28,900	3,704,967	132,581	133,555	27,710	594	3,571	298,011
Total	26,510,378	12,790,670	2,876,437	0	94,988	42,272,472	1,527,976	1,493,250	339,924	6,994	11,737	3,379,881
										GWh		
							Purchased Energy				3,368.1	
Heat Content (Mbtu/Barrel)	6.20	6.20	6.20		5.86		CHP - DG Diesel				11.7	8,093
Barrels	4,275,867	2,063,011	463,941	0	16,209		Total				3,379.9	

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CA Direct Testimony Position - Production Simulation Results

HECO Fuel Consumption and Generation - Excluding DG Diesel
Updated Sales (May 2005)
Maintenance Schedule dated January 12, 2004
Updated Fuel Prices (May 2005)

Month	Fuel Consumption (Mbtu) Kahe	Waiau	Honolulu	Diesel	Total	MWh Generation Kahe	Waiau	Honolulu	Diesel	Total	Net Heat Rate
Jan	2,546,365	1,071,711	141,736	27,203	3,787,015	252,885	98,785	11,055	1,016	363,742	10,411
Feb	2,370,441	893,022	87,655	4,631	3,355,749	235,159	82,021	6,756	189	324,124	10,353
Mar	3,080,207	1,135,871	152,517	39,461	4,408,056	306,025	104,144	11,911	1,515	423,594	10,406
Apr	3,071,765	1,077,865	204,818	119,888	4,474,336	305,591	97,272	16,194	4,298	423,354	10,569
May	2,843,280	987,945	167,329	41,546	4,040,100	281,391	90,958	13,070	1,374	386,794	10,445
Jun	2,829,851	1,085,416	199,397	35,843	4,150,508	280,368	99,084	15,593	1,185	396,231	10,475
Jul	3,079,827	1,087,328	111,722	36,965	4,315,842	305,721	100,072	8,617	1,308	415,718	10,382
Aug	3,061,263	1,207,448	215,646	75,347	4,559,704	304,426	110,581	16,990	2,804	434,802	10,487
Sep	3,433,935	1,147,519	140,783	34,007	4,756,244	341,893	106,015	11,068	1,279	460,253	10,334
Oct	3,423,613	955,403	66,404	2,715	4,448,135	339,293	88,663	5,077	90	433,124	10,270
Nov	3,000,322	996,231	72,984	27,173	4,096,710	296,318	91,869	5,614	944	394,745	10,378
Dec	3,183,586	702,392	26,276	22,294	3,934,549	314,272	64,274	2,021	804	381,372	10,317
Total	35,924,456	12,348,150	1,587,267	467,074	50,326,947	3,563,343	1,133,738	123,966	16,805	4,837,852	10,543
Calibration Factor - ('03-'04 Avg)	1.0098	1.0245	0.9644	1.1760	1.0135						
Adjusted Total	36,274,719	12,650,063	1,530,681	549,255	51,004,719						
Heat Content (Mbtu/Barrel)	6.20	6.20	6.20	5.86							
Barrels	5,850,761	2,040,333	246,884	93,730							

	GWh	
Steam Generated Energy	4,821.0	10,466
CT Generated Energy	16.8	32,683
Central Station Generated Energy	4,837.9	

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CA Direct Testimony Position - Production Simulation Results

Purchased Power and DG Diesel Fuel Consumption and Generation
Updated Sales (May 2005)
Maintenance Schedule dated January 12, 2004
Updated Fuel Prices (May 2005)

Month	Fuel Consumption (Mbtu) AES	Kalaeloa	H-Power	Non-Firm	DG	Total	MWh Generation AES	Kalaeloa	H-Power	Non-Firm	DG	Total
Jan	2,297,956	1,176,500	260,647	0	0	3,735,103	132,581	137,106	30,802	594	0	301,083
Feb	2,075,573	1,064,406	235,421	0	0	3,375,400	119,750	123,852	27,821	536	0	271,960
Mar	2,297,956	856,332	139,200	0	0	3,293,488	132,581	99,941	16,450	594	0	249,565
Apr	2,223,828	633,690	237,291	0	0	3,094,809	128,304	74,188	28,042	575	0	231,109
May	2,297,956	1,186,554	260,647	0	0	3,745,156	132,581	138,180	30,802	594	0	302,157
Jun	2,223,828	1,165,045	252,235	0	0	3,641,108	128,304	135,884	29,808	575	0	294,571
Jul	2,297,956	1,186,229	260,647	0	0	3,744,831	132,581	138,600	30,802	594	0	302,576
Aug	2,297,956	1,208,915	260,647	0	0	3,767,517	132,581	141,272	30,802	594	0	305,248
Sep	1,659,667	1,173,891	252,235	0	0	3,085,793	94,268	137,194	29,808	575	0	261,845
Oct	2,297,956	1,181,267	249,434	0	14,533	3,743,190	132,581	138,046	29,477	594	1,478	302,176
Nov	2,223,828	1,170,754	233,551	0	0	3,628,133	128,304	136,745	27,600	575	0	293,224
Dec	2,297,956	1,184,949	234,482	0	0	3,717,387	132,581	138,377	27,710	594	0	299,262
Total	26,492,413	13,188,531	2,876,437	0	14,533	42,571,914	1,526,996	1,539,384	339,924	6,994	1,478	3,414,776
Heat Content (Mbtu/Barrel)	6.20	6.20	6.20		5.86							
Barrels	4,272,970	2,127,182	463,941	0	2,480							

	GWh	
Purchased Energy	3,413.3	
CHP - DG Diesel	1.5	9,833
Total	3,414.8	

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Hawaiian Electric Company, Inc.

**DERIVATION OF DIESEL FUEL OIL INVENTORY
DERIVED ON DAILY CONSUMPTION BASIS**

Line	Description	CA Reference	Units	HECO DT Filing (a)	CA Output Using HECO DT Filing Inputs (b)	CA DT Position (c)
1.	**Forecast Diesel Fuel Oil Consumption**	CA-304, Page 1	Barrels	11,188	86,852	93,730
2.	**Burn Rate**	Line 1/365 days	Barrels/Day	31	238	257
3.	**35 Day Inventory**	Line 2 x 35 days	Barrels	1,073	8,328	8,988
4.	**Continuous 24 Hour Consumption**	HECO-412	Barrels/Day	5,374	5,374	5,374
5.	**Inventory @ 24 Hour Consumption**	Line 3 / Line 4	Days	0.2	1.5	1.7

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Hawaiian Electric Company, Inc.

DAYS OF FULL LOAD CONSUMPTION

Line	Description	CA Reference	Units	HECO DT Filing (a)	CA Output Using HECO DT Filing Inputs (b)	CA DT Position (c)
	Test Year Diesel Inventory					
1.	**Central Station Diesel**	HECO-413, Page 1	Barrels	21,768	21,768	21,768
2.	**Additional for DG Diesel**	HECO May 2005 Update	Barrels	0	0	500
3.	**Total Diesel Inventory**	Line 1 + Line 2	Barrels	21,768	21,768	22,268
4.	**Full Load Consumption**	HECO-412	Barrels/Day	5,374	5,374	5,374
5.	**Days at Full Load Consumption**	Line 3 / Line 4	Days	4.1	4.1	4.1

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Hawaiian Electric Company, Inc.

ESTIMATED 2005 TEST YEAR PURCHASED ENERGY EXPENSE
($000)

Line	Description		CA Reference	HECO DT Filing (HECO-506) (a)	CA Output Using HECO DT Filing Inputs (b)	CA DT Position (c)
1.	Kalaeloa-	Fuel	CA-WP-309, Page 5	78,817	77,432	113,870
2.		Additive	CA-312, Pages 3, 4	1,920	1,907	1,966
3.		O&M (Non-Fuel)	CA-312, Pages 3, 4	19,268	19,123	19,123
4.		Short-fall		0	0	0
5.	Total			100,005	98,462	134,959
6.	AES Hawaii -	Fuel	CA-WP-309, Page 5	38,752	39,457	61,019
7.		O&M	CA-313, Pages 2, 3	26,410	26,286	26,427
8.	Total			65,162	65,743	87,446
9.	H-Power -	Energy	CA-312, Page 2	24,276	24,276	36,895
10.	Other					
11.		Chevron	CA-312, Page 2	53	53	76
12.		Tesoro	CA-312, Page 2	447	447	672
13.	Total			500	500	748
14.	Total Energy			189,943	188,982	260,048

Note: Totals may not add exactly due to rounding.

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Hawaiian Electric Company, Inc.
Determination of Percent of Purchased Energy Mix,
Payment Rate (in ¢/kwh) and
Composite Cost of Purchased Energy (in ¢/kwh)

	A	B	C	D	E	F
No.	Producer	GWh Purchased	% to Total PP	Payment Rate (¢/kwh)	Weighted Cost (¢/kwh) [(colF ÷ colB) * colC * 1000]	Purch Pwr Fuel Expense ($ thous)
1.	**Kalaeloa**					
	Fuel	1,539.4	45.10	7.397		113,869.9
	Additive			0.128		1,966.3
	Total	1,539.4		7.525	3.394	115,836.2
2.	**AES**					
	Fuel	1,527.0	44.73	3.996	1.787	61,019.3
3.	**HPower**					
	On Peak	198.3	5.81	12.060	0.701	23,915.0
	Off Peak	88.2	2.58	9.160	0.236	8,079.1
	On Peak - excess	0.0	0.00	12.060	0.000	0.0
	Off Peak - excess	53.5	1.57	9.160	0.144	4,900.6
	Total	340.0				36,894.7
4.	**Tesoro**					
	On Peak	3.6	0.11	12.060	0.013	434.2
	Off Peak	2.6	0.08	9.160	0.007	238.2
	Total	6.2				672.3
5.	**Chevron**					
	On Peak	0.4	0.01	12.060	0.001	48.2
	Off Peak	0.3	0.01	9.160	0.001	27.5
	Total	0.7				75.7
6.	**Other**	-	-	0.000	0.000	-
7.	Total	3,413.3	100.00		6.285	214,498.2
	Composite Cost of Purchased Energy				6.285 ¢/kwh	

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Hawaiian Electric Company, Inc.
KALAELOA ESTIMATED TEST YEAR O&M (NON-FUEL) AND ADDITIVE EXPENSES - BASED ON CA OUTPUT USING HECO DT FILING INPUTS

Line	Assumptions:			
1.	Base GNPIPD			73.944
2.	GNPIPD per HECO May 2005 Update			108.409
3.	GNPIPD Ratio (Line 2 / Line 1)			1.466096
4.	O&M (Non-Fuel) Base per KWh, Up to Minimum Purchase		$	0.0096
5.	O&M (Non-Fuel) Base per KWh, Above Minimum Purchase -			
6.		< 180 MW	$	0.0048
7.		> = 180 MW	$	0.0014

Line	Additive	
8.	Base Fuel Additive per KWh	$0.00144
9.	Base PPI Mg Ingots	114.20
10.	2005 PPI Mg Ingots	101.30
11.	PPI Mg Ingots Ratio (10/9)	0.88704028
12.	Test Year Rate per KWh (8x11)	$0.00128
13.	Est. Test Year Energy MWh	1,493,250
14.	Est. Additive Charge $000 (12x13)	$ 1,907

			O&M (Non-Fuel) Energy - MWh			O&M (Non-Fuel) Charge - $000			
Line	Month	MWh (CA-309, P 3)	Up to Min Purch (a) - (c) - (d)	Above Min Purch < 180 MW (HECO-WP-501, P 2)	Above Min Purch > = 180 MW (HECO-WP_501, P 2)	Up to Min Purch	Above Min Purch < 180 MW	Above Min Purch > = 180 MW	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
15.	Rate - $/KWh					$ 0.0141	$ 0.0070	$ 0.0021	
16.	Jan	134,064	134,064	-	-	1,887	-	-	1,887
17.	Feb	120,856	120,856	-	-	1,701	-	-	1,701
18.	Mar	97,853	97,853	-	-	1,377	-	-	1,377
19.	Apr	73,100	43,182	3,922	25,996	608	28	53	689
20.	May	134,377	(1,882)	16,984	119,275	(26)	120	245	338
21.	Jun	131,387	131,387	-	-	1,849	-	-	1,849
22.	Jul	134,256	134,256	-	-	1,890	-	-	1,890
23.	Aug	135,944	135,944	-	-	1,913	-	-	1,913
24.	Sep	132,606	132,606	-	-	1,866	-	-	1,866
25.	Oct	132,943	132,943	-	-	1,871	-	-	1,871
26.	Nov	132,307	132,307	-	-	1,862	-	-	1,862
27.	Dec	133,555	133,555	-	-	1,880	-	-	1,880
28.	Total	1,493,250	1,327,073	20,906	145,271	18,678	147	298	19,123

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Hawaiian Electric Company, Inc.
KALAEOLA ESTIMATED TEST YEAR O&M (NON-FUEL) AND ADDITIVE EXPENSES - CA DT POSITION

Line	Assumptions			
1.	Base GNPIPD			73.944
2.	GNPIPD per HECO May 2005 Update			109.099
3.	GNPIPD Ratio (Line 2 / Line 1)			1.475427
4.	O&M (Non-Fuel) Base per KWh, Up to Minimum Purchase		$	0.0096
5.	O&M (Non-Fuel) Base per KWh, Above Minimum Purchase -			
6.		< 180 MW	$	0.0048
7.		> = 180 MW	$	0.0014

Line	Additive	
8.	Base Fuel Additive per KWh	$0.00144
9.	Base PPI Mg Ingots	114.20
10.	2005 PPI Mg Ingots	101.30
11.	PPI Mg Ingots Ratio (10/9)	0.88704028
12.	Test Year Rate per KWh (8x11)	$0.00128
13.	Est. Test Year Energy MWh	1,539,384
14.	Est. Additive Charge $000 (12x13)	$ 1,966

			O&M (Non-Fuel) Energy - MWh			O&M (Non-Fuel) Charge - $000			
Line	Month	MWh (CA-309, P 5)	Up to Min Purch (a) - (c) - (d)	Above Min Purch < 180 MW (HECO-WP-501, P 2)	Above Min Purch > = 180 MW (HECO-WP-501, P 2)	Up to Min Purch	Above Min Purch < 180 MW	Above Min Purch > = 180 MW	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
15.	Rate - $/KWh					$ 0.0142	$ 0.0071	$ 0.0021	
16.	Jan	137,106	137,106	-	-	1,942	-	-	1,942
17.	Feb	123,852	123,852	-	-	1,754	-	-	1,754
18.	Mar	99,941	99,941	-	-	1,416	-	-	1,416
19.	Apr	74,188	44,270	3,922	25,996	627	28	54	709
20.	May	138,180	1,921	16,984	119,275	27	120	246	394
21.	Jun	135,884	135,884	-	-	1,925	-	-	1,925
22.	Jul	138,600	138,600	-	-	1,963	-	-	1,963
23.	Aug	141,272	141,272	-	-	2,001	-	-	2,001
24.	Sep	137,194	137,194	-	-	1,943	-	-	1,943
25.	Oct	138,046	138,046	-	-	1,955	-	-	1,955
26.	Nov	136,745	136,745	-	-	1,937	-	-	1,937
27.	Dec	138,377	138,377	-	-	1,960	-	-	1,960
28.	Total	1,539,384	1,373,207	20,906	145,271	19,450	148	300	19,898

Hawaiian Electric Company, Inc.

ESTIMATED 2005 TEST YEAR FIRM CAPACITY EXPENSE

Line	Description	CA Reference	HECO DT Filing (HECO-507) (a)	CA Output Using HECO DT Filing Inputs (b)	CA DT Position (c)
1.	**Firm Capacity Producer**				
2.	**Kalaeloa**	HECO-507, Page 1	32,831	32,831	32,831
3.	**AES Hawaii**	CA-313, Pages 2, 3	67,702	67,376	67,333
4.	**H-Power**	HECO-507, Page 1	6,901	6,901	6,901
5.	**AES Hawaii Bonus**	CA-313, Page 4	1,187	1,187	1,228
6.	**Total**		108,621	108,295	108,293

Note: Totals may not add exactly due to rounding.

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AES Estimated Test Year Expenses for Capacity and O&M Charges
Based on CA Output Using HECO DT Filing Inputs

Line	Assumptions	
1.	Base GNPIPD	72.465
2.	GNPIPD 3Q 2004	107.864
3.	GNPIPD 1Q 2005	108.958
4.	Capacity Charge	0.044095
5.	Variable O&M Charge	0.0005
6.	Fixed O&M Charge	0.011

					O&M Charges		
Line	Month	MWh	GNPIPD Ratio	Capacity Charge	Variable	Fixed	Total
		(a)	(b)	(c)	(d)	(e)	(f)
7.	Jan	132,581	1.488498	5,846,150	98,673	2,170,809	2,269,482
8.	Feb	119,750	1.488498	5,280,394	89,124	1,960,730	2,049,855
9.	Mar	132,581	1.488498	5,846,150	98,673	2,170,809	2,269,482
10	Apr	128,304	1.488498	5,657,565	95,490	2,100,783	2,196,273
11.	May	132,581	1.488498	5,846,150	98,673	2,170,809	2,269,482
12.	Jun	128,304	1.488498	5,657,565	95,490	2,100,783	2,196,273
13.	Jul	132,581	1.503595	5,846,150	99,674	2,192,826	2,292,500
14.	Aug	132,581	1.503595	5,846,150	99,674	2,192,826	2,292,500
15.	Sep	95,248	1.503595	4,199,956	71,607	1,575,357	1,646,964
16.	Oct	132,581	1.503595	5,846,150	99,674	2,192,826	2,292,500
17.	Nov	128,304	1.503595	5,657,565	96,459	2,122,090	2,218,548
18.	Dec	132,581	1.503595	5,846,150	99,674	2,192,826	2,292,500
19.	Total	1,527,976		67,376,097	1,142,885	25,143,471	26,286,356

Notes: MWh from CA-309, Page 3

Capacity Charge = Available energy (MWh) *1,000 KWh/MWh * Capacity Charge

Variable O&M = Available energy (MWh) * 1,000 kWh/MWh * Variable O&M Charge * GNPIPD Ratio

Fixed O&M Charge = Available energy (MWh) * 1,000 kWh/MWh * Fixed O&M Charge * GNPIPD Ratio

O&M Charges = Variable O&M Charge + Fixed O&M Charge

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AES Estimated Test Year Expenses for Capacity and O&M Charges - CA DT Position

Line	Assumptions	
1.	Base GNPIPD	72.465
2.	GNPIPD 3Q 2004	108.479
3.	GNPIPD 1Q 2005	109.642
4.	Capacity Charge	0.044095
5.	Variable O&M Charge	0.0005
6.	Fixed O&M Charge	0.011

					O&M Charges		
Line	Month	MWh	GNPIPD Ratio	Capacity Charge	Variable	Fixed	Total
		(a)	(b)	(c)	(d)	(e)	(f)
7.	Jan	132,581	1.496985	5,846,150	99,236	2,183,186	2,282,422
8.	Feb	119,750	1.496985	5,280,394	89,632	1,971,910	2,061,542
9.	Mar	132,581	1.496985	5,846,150	99,236	2,183,186	2,282,422
10	Apr	128,304	1.496985	5,657,565	96,035	2,112,760	2,208,795
11.	May	132,581	1.496985	5,846,150	99,236	2,183,186	2,282,422
12.	Jun	128,304	1.496985	5,657,565	96,035	2,112,760	2,208,795
13.	Jul	132,581	1.513034	5,846,150	100,300	2,206,592	2,306,891
14.	Aug	132,581	1.513034	5,846,150	100,300	2,206,592	2,306,891
15.	Sep	94,268	1.513034	4,156,739	71,315	1,568,934	1,640,249
16.	Oct	132,581	1.513034	5,846,150	100,300	2,206,592	2,306,891
17.	Nov	128,304	1.513034	5,657,565	97,064	2,135,411	2,232,475
18.	Dec	132,581	1.513034	5,846,150	100,300	2,206,592	2,306,891
19.	Total	1,526,996		67,332,880	1,148,986	25,277,700	26,426,686

Notes:
MWh from CA-309, Page 5
Capacity Charge = Available energy (MWh) *1,000 KWh/MWh * Capacity Charge
Variable O&M = Available energy (MWh) * 1,000 kWh/MWh * Variable O&M Charge * GNPIPD Ratio
Fixed O&M Charge = Available energy (MWh) * 1,000 kWh/MWh * Fixed O&M Charge * GNPIPD Ratio
O&M Charges = Variable O&M Charge + Fixed O&M Charge

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Hawaiian Electric Company, Inc.

AES AVAILABILITY BONUS

Line	Description	CA Reference	Units	HECO DT Filing (a)	CA Output Using HECO DT Filing Inputs (b)	CA DT Position (c)
1.	GNPIPD Current (forecasted 1st Q for year of payment)	CA-313, Pages 2, 3	N/A	108.958	108.958	109.642
2.	GNPIPD Base	CA-313, Pages 2, 3	N/A	72.465	72.465	72.465
3.	GNPIPD Adjustment Factor	Line 1 / Line 2	N/A	1.5036	1.5036	1.5130
4.	C = Capacity Charge	CA-313, Pages 2, 3	¢/kWh	4.4095	4.4095	4.4095
5.	U = Unescalated Energy Charge (Fuel equation with 180 MW * EAF as input for plant load + Variable O&M component (0.05 cents/kWh) + Fixed O&M component (1.1 cents/kWh))	HECO-WP-503, Page 3	¢/kWh	2.84	2.84	2.84
6.	E = Escalated Energy Charge (U*GNPIPD Current/GNPIPD base)	Line 5 * Line 3	¢/kWh	4.2702	4.2702	4.2970
7.	((C+U)/(C+E))		¢/kWh	0.835223821	0.835223821	0.832652214
8.	Equivalent Availability Factor	HECO-WP-503, Page 3		97.36%	97.36%	97.59%
9.	EAF > 91% (truncated to nearest 0.1%)	Line 8 - 91%		6.3%	6.3%	6.5%
10.	Bonus Uncorrected ($15,000 for each 0.1%)	Line 9 * $15,000	$000	$ 945	$ 945	$ 975
11.	Bonus Corrected	Line 10 * Line 3 * Line 7	$000	$ 1,187	$ 1,187	$ 1,228

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Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING MODIFIED FOR CHP
Current Effective Rates

Line		
1	**Effective Date**	2005 Norm. Test Year
2	**Supercedes Factor**	-
	GENERATION COMPONENT	
	FUEL PRICES, ¢/MBTU	
3	Honolulu	913.75
4	Kahe	866.89
5	Waiau-Steam	866.89
6	Waiau-Waste	0.00
7	Waiau-Diesel	1,356.56
	BTU MIX, %	
8	Honolulu	3.00%
9	Kahe	71.12%
10	Waiau-Steam	24.80%
11	Waiau-Waste	0.00
12	Waiau-Diesel	1.08%
13	COMPOSITE COST OF GENERATION, ¢/MBTU	873.57
14	% Input to system kWh Mix	58.64%
15	Generation Efficiency Factor, Mbtu/kWh	0.011170
16	WEIGHTED COMPOSITE GEN COST, ¢/kWh (Line 13 x 14 x 15)	5.72200
17	BASE GENERATION COST, ¢/Mbtu	287.83
18	Base % Input to System kWh Mix	58.64
19	Efficiency Factor, Mbtu/kWh	0.011170
20	WEIGHTED BASE GEN COST, ¢/kWh (Line 17 x 18 x 19)	1.88531
21	Cost Less Base (Line 16 - 20)	3.83669
22	Revenue Tax Req Multiplier	1.0975
23	GENERATION FACTOR, ¢/KWH (Line 21 x 22)	4.21077
	DG ENERGY COMPONENT	
24	COMPOSITE COST OF DG ENERGY, ¢/kWh	13.566
25	% Input to System kWh Mix	0.02%
26	WTD COMP DG ENRGY COST, ¢/KWH (Line 24 x 25)	0.00200
27	BASE DG ENERGY COMP COST	0.000
28	Base % Input to System kWh Mix	0.00
29	WTD BASE DG ENERGY COST, ¢/KWH (Line 27 x 28)	0.00000
30	Cost Less Base (Line 26 - 29)	0.00200
31	Loss Factor	1.059
32	Revenue Tax Req Multiplier	1.0975
33	DG FACTOR, ¢/KWH (Line 30 x 31 x 32)	0.00232
34	TOTAL GENERATION FACTOR ¢/KWH (Line 23 + 33)	4.21309

Line				
	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE - ¢/KWH			
35	THC	- On Peak		12.060
36		- Off Peak		9.160
37	HRRV	- On Peak		12.060
38		- Off Peak		9.160
39	HRRV	- On Peak	(excess)	12.060
40		- Off Peak	(excess)	9.160
41	Chevron	- On Peak		12.060
42		- Off Peak		9.160
43	Kalaeloa			7.525
44	AES-HI			3.996
	PURCHASED ENERGY KWH MIX, %			
45	THC	- On Peak		0.11
46		- Off Peak		0.08
47	HRRV	- On Peak		5.81
48		- Off Peak		2.58
49	HRRV	- On Peak	(excess)	0.00
50		- Off Peak	(excess)	1.57
51	Chevron	- On Peak		0.01
52		- Off Peak		0.01
53	Kalaeloa			45.10
54	AES-HI			44.73
55	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			6.285
56	% Input to System kWh Mix			41.35
57	WTD CMP PURCH ENRGY COST, ¢/KWH (Line 55 x 56)			2.59852
58	BASE PURCH ENERGY COMP COST			3.005
59	Base % Input to System kWh Mix			41.36
60	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 58 x 59)			1.24287
61	Cost Less Base (Line 57 - 60)			1.35565
62	Loss Factor			1.059
63	Revenue Tax Req Multiplier			1.0975
64	PURCHASED ENERGY FACTOR, ¢/KWH (Line 61 x 62 x 63)			1.57561

Line	**SYSTEM COMPOSITE**	
65	Total Generation and Purchased Energy Factor (Line 34 + 64)	5.78870
66	Adjustment, ¢/kWh	0.000
67	ECA Reconciliation Adjustment, ¢/kWh	0.000
68	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 65 + 66 + 67)	5.789

Hawaiian Electric Company, Inc.

**DERIVATION OF TEST YEAR 2005
AVOIDED ENERGY COST PAYMENT RATES**

Avoided Energy Rate - over 100 KW

Line	Description	ON-PEAK		OFF-PEAK		SOURCE
1.	**Heat Rate**	13,382	BTU / NET KWH	9,929	BTU / NET KWH	Docket #4569, HECO-101
2.	**Composite Fuel Cost of Total Generation (HECO & CHP)**	873.57	¢ / MMBTU	873.57	¢ / MMBTU	Test Year 2005 Composite Fuel Cost
3.	**1 MMBTU / 1,000,000 BTU**	1,000,000	BTU / MMBTU	1,000,000	BTU / MMBTU	
4.	**Unadjusted Payment Rate (Line 1 x 2) / Line 3**	11.69	¢ / NET KWH	8.67	¢ / NET KWH	
5.	**O&M Adjustment**	0.37	¢ / NET KWH	0.49	¢ / NET KWH	Appendix A, D&O 8298
6.	**BASE Avoided Energy Payment Rate**	12.06	¢ / NET KWH	9.16	¢ / NET KWH	

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Hawaiian Electric Company, Inc.

Determination of Base Fuel Energy Charge at Proposed Rates
(¢/kWh)

Line	Description	CA Reference	CA DT Position
1.	**Weighted Base Cost**	CA-304, Page 2/CA-303, Page1	5.67159
2.	**Revenue Tax Factor**	CA-IR-358	1.0975
3.	**Generation Fuel Cost Component**	Line 1 x Line 2	6.22457
4.	**Weighted Base DG Energy Cost**	CA-304, Page 2/CA-303, Page1	0.02552
5.	**Revenue Tax Factor**	CA-IR-358	1.0975
6.	**DG Fuel Cost Component**	Line 4 x Line 5	0.02801
7.	**Weighted Base Purchased Energy Cost**	CA-301, Page 1/CA-303, Page1	8.88204
8.	**Revenue Tax Factor**	CA-IR-358	1.0975
9.	**Purchased Energy Cost Component**	Line 7 x Line 9	9.74804
10.	**Base Fuel Energy Charge at Proposed Rates**	Line 3 + Line 7 + Line 9	16.00063

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Power Factor--
The Basics

We hope to give you an explanation of what power factor is, and to answer the following questions:

- Question #1: What is Power Factor?
- Question #2: What Causes Low Power Factor?
- Question #3: Why Should I Improve My Power Factor?
- Question #4: How Do I Correct (Improve) My Power Factor?
- Question #5: How Long Will it Take My Investment in Power Factor Correction to Pay for Itself?

Question #1

What is Power Factor?

To understand power factor, we'll first start with the definition of some basic terms:

- **KW** is Working Power (also called Actual Power or Active Power or Real Power). It is the electric energy that actually powers the equipment and performs useful work.
- **KVAR** is Reactive Power. It is the power that magnetic equipment (transformer, motor and relay) needs to produce the magnetizing flux.
- **KVA** is Apparent Power. It is the "vectorial summation" of KVAR and KW.

Let's look at an analogy in order to better understand these terms…

Let's say you are at the ballpark and it is a really hot day. You order up a mug of your favorite brewsky. The thirst-quenching portion of your beer is represented by KW (Figure 1).

Unfortunately, life isn't perfect. Along with your ale comes a little bit of foam. (And let's face it…that foam just doesn't quench your thirst.) This foam is represented by KVAR.

The total contents of your mug, KVA, is the summation of KW (the beer) and KVAR (the foam).

Figure 1

So, now that we understand some basic terms, we are ready to learn about power factor.

Power Factor (P.F.) is the ratio of Working Power to Apparent Power.

$$P.F. = \frac{KW}{KVA}$$

Thus, for a given KVA:

- The more foam you have, the lower your ratio of KW (beer) to KVA (beer plus foam). Thus, the lower your power factor percentage.
- The less foam you have, the higher your ratio of KW (beer) to KVA (beer plus foam). In fact, as your foam (or KVAR) approaches zero, your power factor approaches 100%.

Question #2:

What Causes Low Power Factor?

Since power factor is defined as the ratio of KW to KVA, we see that low power factor results when KW is small in relation to KVA. Remembering our beer mug analogy, this would occur when KVAR (foam) is large.

What causes a large KVAR in a system? The answer is…..**inductive loads.**

Inductive loads (which are sources of Reactive Power) include:

- Transformers
- Induction Motors
- High Intensity Discharge (HID) Lighting

These inductive loads constitute a major portion of the power consumed in industrial complexes. Reactive power (KVAR) required by inductive loads increases the amount of apparent power (KVA) in the electric system. So, inductive loads (with large KVAR) result in low power factor.

Question #3

Why Should I Improve My Power Factor?

Okay. So I've got inductive loads at my facility that are causing my power factor to be low. Why should I want to improve it?

You want to improve your power factor for several different reasons. Some of the benefits of improving your power factor include:

1) **Lower utility fees** by:

   a. Reducing peak KW billing demand

      Recall that inductive loads, which require reactive power, caused your low power factor. This increase in required reactive power (KVAR) causes an increase in required apparent power (KVA), which is what the electric system is supplying.

      So, a facility's low power factor causes the electric system to increase its generation, transmission, distribution and transformer capacity in order to handle this extra apparent power (KVA) demand. Also, a facility's low power factor increases the energy losses on the electric system.

      By lowering your power factor, you require less KVA from the electric system. This equates to a dollar savings from the utility.

   b. Eliminating the power factor penalty

      Utilities usually charge customers an additional fee when their power factor is less than 95%. In fact, power factor less than 70% will not be permitted by most electric systems and the customer will be required to install, at their own expense, such corrective equipment as may be necessary to improve power factor.

2) **Increased system capacity** and **reduced system losses** in your electrical system

By adding capacitors (KVAR generators), the power factor is improved and the KW capacity of the system is increased.

Uncorrected power factor causes power system losses in your distribution system. By improving your power factor, these losses can be reduced. And with lower system losses, you are also able to add additional load to your system.

3) **Increased voltage level** in your electrical system and **cooler, more efficient motors**

As mentioned above, uncorrected power factor causes power system losses in your distribution system. As power losses increase, you may experience voltage drops. Excessive voltage drops can cause overheating and premature failure of motors and other inductive equipment.

So, by raising your power factor, you will minimize these voltage drops along feeder cables and avoid related problems. Your motors will run cooler and be more efficient, with a slight increase in capacity and starting torque.

Question # 4

How Do I Correct (Improve) My Power Factor?

All right. You've convinced me. I sure would like to save some money on my power bill and extend the life of my motors. But how do I go about improving (i.e., increasing) my power factor?

We have seen that **sources of Reactive Power** (inductive loads) decrease power factor:

- Transformers
- Induction motors
- High Intensity Discharge (HID) Lighting

Similarly, **consumers of Reactive Power** increase power factor:

- Capacitors
- Synchronous generators (utility and emergency)
- Synchronous motors

Thus, it comes as no surprise that one way to increase power factor is to add capacitors to the system. This--and other ways of increasing power factor--are listed below:

1) **Installing capacitors (KVAR Generators)**

   Installing capacitors decreases the magnitude of reactive power (KVAR or foam), thus increasing your power factor.

2) **Minimizing operation of idling or lightly loaded motors**

   We already talked about the fact that low power factor is caused by the presence of induction motors. But, more specifically, low power factor is caused by running induction motors lightly loaded.

3) **Avoiding operation of equipment above its rated voltage.**

4) **Replacing standard motors as they burn out with energy--efficient motors.**

   Even with energy-efficient motors, power factor is significantly affected by variations in load. A motor must be operated near its rated load in order to realize the benefits of a high power factor design.

Question #5

How Long Will it Take My Investment in Power Factor Correction to Pay for Itself?

Super. I've learned that by installing capacitors at my facility, I can improve my power factor. But buying capacitors costs money. How long will it take for the reduction in my power bill to pay for the cost of the capacitors?

Using the following three steps, a calculation can be run to determine when this payoff will be:

1) Determine **amount of power factor penalty** caused by your low power factor.

2) Determine what needs to be done at your facility to improve the situation. Bring in an electrician or other qualified person to estimate the **cost of power improvement**.

3) **Calculate the payback by** comparing the power factor penalty to be avoided with the power factor improvement cost.

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DOCKET NO. 04-0113

WORKPAPERS

OF

JOSEPH A. HERZ

Hawaiian Electric Company, Inc.
Fuel Prices and Heat Contents As of May 2005

Plant	Unit	Price ($/Barrel)	Heat Content (mBtu/Barrel)	Fuel Type	Transmission Penalty Factor	Not Used	Comments
FCODE(MC)		FDOLR(FC)	FBTU(FC)		FADJST(FC)	not used	
K	BBLS	18.2283	6.2000	LSO	0.977	PF	(1/1.024 = 0.977 AS SHOWN)
W	BBLS	17.8837	6.2000	LSO	1.002	PF	
V	BBLS	17.8123	6.2000	LSO	0.998	PF	
H	BBLS	17.9737	6.2000	LSO	0.996	PF	
D	BBLS	23.0824	5.8600	DIESEL	1.002	PF	
B	BBLS	1.0310	1.0000	KAL	1.031	PF	
A	BBLS	1.3281	1.0000	AES	1.031	PF	(TYPE A FOR FIRST SIX MONTHS)
S	BBLS	17.8837	6.2000	LSO	1.002	PF	(SAME AS W, EXCEPT BASE LOAD)
a	BBLS	1.3455	1.0000	AES	1.031	PF	(TYPE A FOR LAST SIX MONTHS)

Hawaiian Electric Company, Inc.
2005 Fuel Price Information

Fuel	Heat Content (mbtu/unit)	Unit	Fuel Price ($/bbl) November 12, 2004 [1]	Fuel Price ($/bbl) May 5, 2005 [2]
Low-Sulfur Fuel Oil	6.20	Barrel	34.7257	53.7346
Diesel	5.86	Barrel	56.8000	79.4392

[1] CA-IR-154, Docket No. 04-0113, Page 1 of 3.

[2] HECO 2005 Test Year Rate Case - Updates dated May 2005, Attachment 1B, Page 1 of 1.

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Hawaiian Electric Company, Inc.
2005 Generation Unit Fuel and Variable
Operation and Maintenance Costs

Generating Unit	Unit Type	Dependable Capacity (MW)		Heat Rate			Heat Rate	Start-Up Fuel	Minimum Uptime	Fuel Type	Fuel Cost		Variable O & M	Transmission Penalty Factor	Equivalent Forced Outage Rate	Maintenance Outage	Dispatch Costs
		Min	Max	A	B	C	(Btu/kWh)				($/MMBtu)	($/MWh)	($/MWh)		(%)	(Days)	($/MWh)
Kahe 1	Steam	27.7	88.2	87.8473	7.8998	0.015158	10,214	5044.00	1	LSFO		57.21	0.5372	1.0260	1.80	63	57.74
Kahe 2	Steam	27.9	86.3	67.3086	8.3691	0.01044	10,133	5044.00	1	LSFO		56.75	0.47777	1.0260	1.87	0	57.23
Kahe 3	Steam	27.8	88.2	104.9663	7.1759	0.01870	10,037	5044.00	1	LSFO		56.22	0.44932	1.0260	1.68	19	56.67
Kahe 4	Steam	27.8	89.2	82.4654	7.9495	0.01071	9,940	5044.00	1	LSFO		55.68	0.45021	1.0260	4.11	92	56.13
Kahe 5	Steam	50.4	134.7	119.9209	8.3243	0.00530	9,897	4586.00	1	LSFO		55.43	0.48720	1.0260	1.13	0	55.92
Kahe 6	Steam	40.1	133.9	128.2775	8.0351	0.00744	10,212	9274.00	1	LSFO		57.20	0.44325	1.0260	2.19	64	57.64
Waiau 3	Steam	22.1	46.2	69.3131	8.4589	0.04500	13,820	337.00	3	LSFO		77.41	0.57845	1.0060	4.90	0	77.99
Waiau 4	Steam	22.3	46.4	49.0463	9.2332	0.03176	13,765	337.00	3	LSFO		77.10	0.58015	1.0060	6.16	99	77.68
Waiau 5	Steam	22.6	54.6	31.2522	10.1776	0.00993	12,446	277.00	3	LSFO		69.71	0.57154	1.0120	2.57	14	70.28
Waiau 6	Steam	22.5	55.6	61.2878	8.5866	0.02068	12,163	277.00	3	LSFO		68.12	0.52253	1.0120	3.30	0	68.64
Waiau 7	Steam	32.7	88.1	61.5747	8.6611	0.00897	10,308	5044.00	1	LSFO		57.73	0.46490	1.0120	1.19	0	58.20
Waiau 8	Steam	32.7	88.1	105.5491	6.9434	0.02343	10,373	5044.00	1	LSFO		58.10	0.45779	1.0120	1.79	0	58.55
Waiau 9	CT	13.9	51.9	198.6939	7.8497	0.02922	22,071	11.80	1	LSFO		213.93	0.93681	1.0120	35.86	68	214.87
Waiau 10	CT	13.9	49.9	191.3958	7.2757	0.02851	21,724	11.80	1	LSFO		210.57	0.85954	1.0120	20.81	68	211.43
Honolulu 8	Steam	22.3	52.9	56.7792	10.5093	0.00800	12,816	190.00	3	LSFO		79.53	0.61052	0.9970	7.52	0	80.14
Honolulu 9	Steam	22.5	54.4	62.6737	9.4038	0.01947	12,936	190.00	3	LSFO		80.28	0.57553	0.9970	6.42	0	80.85
AES-Hawaii	Steam	63.0	180.0	258.7479	14.9713	0.0051019		0.00	1	Coal		25.31		1.0290	1.00	14	25.31
H-POWER	Steam	25.0	46.0	10.0000	8.2000	0.00010		0.00	1	LSFO		79.00		1.0000	90.00[1]	39	79.00
Kalaeloa AC	Steam	0.0	29.0	0.0100	8.734068	0.0000010		0.00	1	LSFO		53.72		1.0290	1.00	0	53.72
Kalaeloa CT1	Combined Cycle	32.5	90.0	299.0260	4.43444	0.009308		0.00	1	LSFO		53.72		1.0290	1.00	8	53.72
Kalaeloa CT2	Combined Cycle	32.5	90.0	299.0260	4.43444	0.009308		0.00	1	LSFO		53.72		1.0290	1.00	29	53.72
UtilCHP	Combined Heat									LSFO		76.61				0	76.61

[1] H-Power is Availability Factor
[2] H-Power Fuel Cost - On-Peak Rate Shown, Off-Peak Rate is 60.80 ($/MWh), HECO WP-1032, Page 3
[3] Heat Rate for year 2004 and provided by HECO in CA-IR-685

Hawaiian Electric Company, Inc.
Generating Unit Characteristics[1]
Input File Printed with HECO Response to CA-IR-501

Unit	Fuel Type		Minimum (MW)	Maximum (MW)	Cold Start (mBtu)	Hot Start (mBtu)	Minimum Duration (Hours)	Coefficient A	Coefficient B	Coefficient C	Hours per Year	EFOR
B2	B	B	33	90	0.0000	0.0000	-1	299.0260	4.43444	0.009308	8760	0.0100
B1	B	B	33	90	0.0000	0.0000	-1	299.0260	4.43444	0.009308	8760	0.0100
B3	B	B	0	29	0.0000	0.0000	-1	0.01000	8.73407	0.000001	8760	0.0100
A2	A	A	63	180	0.0000	0.0000	-1	258.7479	14.97130	0.0051019	8760	0.0100
A1	A	A	63	90	0.0000	0.0000	-1	258.7479	14.97130	0.0051019	8760	0.0100
K5	K	K	50	134.7	4586.0000	4586.0000	-1	119.9209	8.32430	0.00530	8760	0.0113
W7	W	S	33	88.1	5044.0000	5044.0000	-1	61.5747	8.66110	0.00897	8760	0.0119
K4	K	K	28	89.2	5044.0000	5044.0000	-1	82.4654	7.94950	0.01071	8760	0.0411
W8	W	S	33	88.1	5044.0000	5044.0000	-1	105.5491	6.94340	0.02343	8760	0.0179
K2	K	K	28	86.3	5044.0000	5044.0000	-1	67.3086	8.36910	0.01044	8760	0.0187
K3	K	K	28	88.2	5044.0000	5044.0000	-1	104.9663	7.17590	0.01870	8760	0.0168
K1	K	K	28	88.2	5044.0000	5044.0000	-1	87.8473	7.89980	0.015158	8760	0.0180
K6	K	K	40	133.9	9274.0000	9274.0000	-1	128.2775	8.03510	0.00744	8760	0.0219
G1	W	D	14	51.9	11.8000	11.8000	-1	198.6939	7.84970	0.02922	0	0.3586
G2	W	D	14	49.9	11.8000	11.8000	-1	191.3958	7.27570	0.02851	0	0.2081
W6	W	W	23	55.6	277.0000	277.0000	-3	61.2878	8.58660	0.02068	0	0.0330
H9	H	H	23	54.4	190.0000	190.0000	-3	62.6737	9.40380	0.01947	0	0.0642
W5	W	W	23	54.6	277.0000	277.0000	-3	31.2522	10.17760	0.00993	0	0.0257
H8	H	H	22	52.9	190.0000	190.0000	-3	56.7792	10.50930	0.00800	0	0.0752
W4	W	V	22	46.4	337.0000	337.0000	-3	49.0463	9.23320	0.03176	0	0.0616
W3	W	V	22	46.2	337.0000	337.0000	-3	69.3131	8.45890	0.04500	0	0.0490

[1] Information Provided in Response to CA-IR-501/HE05TY2X.UPF in support of 2005 HECO Rate filing of November 2004

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Hawaiian Electric Company, Inc.
Generating Unit Characteristics[1]
HECO Response to CA-IR-128 Revised as of May 2005

Unit	Fuel Type	Minimum (MW)	Maximum (MW)	Cold Start (mBtu)	Hot Start (mBtu)	Minimum Duration (Hours)	Coefficient A	Coefficient B	Coefficient C	Hours per Year	EFOR
B2	B B	33	90	0.0000	0.0000	-1	299.0260	4.43444	0.009308	8760	0.0100
B1	B B	33	90	0.0000	0.0000	-1	299.0260	4.43444	0.009308	8760	0.0100
B3	B B	0	29	0.0000	0.0000	-1	0.01000	8.73407	0.000001	8760	0.0100
A2	A A	63	180	0.0000	0.0000	-1	258.7479	14.97130	0.0051019	8760	0.0100
A1	A A	63	90	0.0000	0.0000	-1	258.7479	14.97130	0.0051019	8760	0.0100
K5	K K	50	134.7	4586.0000	4586.0000	-1	89.34437	8.64339	0.00305	8760	0.0113
W7	W S	33	88.1	5044.0000	5044.0000	-1	88.21069	7.94047	0.01961	8760	0.0119
K4	K K	28	89.2	5044.0000	5044.0000	-1	75.55387	8.43939	0.00739	8760	0.0411
W8	W S	33	88.1	5044.0000	5044.0000	-1	86.87118	8.09192	0.01315	8760	0.0179
K2	K K	28	86.3	5044.0000	5044.0000	-1	46.00372	9.09521	0.00350	8760	0.0187
K3	K K	28	88.2	5044.0000	5044.0000	-1	57.48642	8.51694	0.00634	8760	0.0168
K1	K K	28	88.2	5044.0000	5044.0000	-1	73.49912	8.17333	0.012920	8760	0.0180
K6	K K	40	133.9	9274.0000	9274.0000	-1	117.06090	8.18188	0.00769	8760	0.0219
G1	W D	14	51.9	11.8000	11.8000	-1	198.6939	7.84970	0.02922	0	0.3586
G2	W D	14	49.9	11.8000	11.8000	-1	191.3958	7.27570	0.02851	0	0.2081
W6	W W	23	55.6	277.0000	277.0000	-3	64.11038	8.74074	0.03199	0	0.0330
H9	H H	23	54.4	190.0000	190.0000	-3	69.89196	8.94844	0.02204	0	0.0642
W5	W W	23	54.6	277.0000	277.0000	-3	61.05946	8.81372	0.02981	0	0.0257
H8	H H	22	52.9	190.0000	190.0000	-3	36.41316	10.31147	0.00568	0	0.0752
W4	W V	22	46.4	337.0000	337.0000	-3	49.46043	9.31119	0.03203	0	0.0616
W3	W V	22	46.2	337.0000	337.0000	-3	146.53942	4.81132	0.08544	0	0.0490

[1] Information Provided in Response to CA-IR-128 Revised as of May 2005.
Shading shows units with revised heat rate ABC Coefficients.

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Hawaiian Electric Company, Inc.
Generating Unit Planned Outage Schedule[1]
From HECO DT Testimony Dated November 2004

Unit	Outage Period Start	End	Days	Total (Days)	Remarks
Capacity Resources					
Kahe 1	Jan 01	Jan 13	13		Outage (blr inspect, permit exp 1-22-05)
	Jul 22	Sep 09	50	63	OH(cndsnsr retbe, annctr, MS p'png rpl, op console, main/aux xfmer,excitation)
Kahe 3	Nov 11	Nov 29	19	19	Outage (blr inspection, permit expires 08/12/06)
Kahe 4	Apr 08	Jul 08	92	92	Overhaul (blr ctrls upgrade, annunciator)
Kahe 6	Jan 14	Mar 18	64	64	Overhaul (blr, annunciator upgrade, SSH tubes rpl, RSH tubes rpl)
Waiau 4	Sep 23	Dec 30	99	99	Overhaul (blr ctrls upgrade, annunciator)
Waiau 5	Jan 01	Jan 14	14	14	Outage (blr inspect, permit exp 9/18/05 if not done in 9/04
Waiau 9	Jan 17	Mar 25	68	68	Major (Comprssr, HG, Cl), Gen, Exh/Int Duct Repl, Processor
Waiau 10	Apr 25	Jul 01	68	68	Major (Comprssr, HG, Cl), Gen, Exh/Int Duct Repl, Processor
Capacity Purchases					
AES-Hawaii	Sep 12	Sep 25	14	14	90 MW Loss, Boiler Inspection
H-POWER	Mar 12	Mar 19	8		23 MW Loss
	Mar 30	Apr 04	6		23 MW Loss
	Oct 29	Nov 05	8		23 MW Loss
	Dec 02	Dec 08	7	29	23 MW Loss
Kalaeloa CT1	Mar 27	Apr 02	7		180 MW Loss, CT1 B Inspection ST Outage
	Oct 22	Oct 22	1	8	90 MW Loss, CT1 A Inspection
Kalaeloa CT2	Mar 20	Mar 26	7		90 MW Loss, CT2 C Inspection
	Apr 03	Apr 23	21		90 MW Loss CT2 Inspection
	Oct 15	Oct 15	1	29	90 MW Loss, CT2 A Inspection

[1] CA-IR-46 Docket No. 04-0113, Page 4 of 11.

Hawaiian Electric Company, Inc.
Generating Unit Planned/Maintenance Outage Schedule[1]
Provided with HECO's Response to CA-IR-43 (Revised) Dated 4/21/2005

Unit	Outage Period Start	End	Days	Total (Days)	Remarks
Capacity Resources					
Kahe 1	Oct 01	Oct 23	23	23	Maintenance Outage
Kahe 2	Jul 10	Sep 07	60	60	Overhaul (HRH bend, M bend, annunicator upgrade, Trb LP)
Kahe 3	Jan 23	Feb 02	11	11	Maintenance Outage, Blr Inspct, AH Baskets replacement
Kahe 5	Jan 02	Jan 22	21	21	Outage #7 vibration, seal oilfilter, aph bering cover leak APH wash
Kahe 6	May 06	Jul 05	61	61	Overhaul (blr, annunciator upgrade, SSH tubes rpl, RSH tubes rpl)
Waiau 4	Sep 23	Dec 28	97	97	Overhaul (HP/LP.Gen, exciter upgrade, condsr wtr box rpl)
Waiau 5	Nov 01	Nov 23	23	23	Maintenance Outage
Waiau 6	Jan 28	Apr 05	68	68	Overhaul (HP blades, annunciator panel, blr refractory)
Waiau 7	Mar 28	Apr 13	17	17	Maintenance Outage tunnel clean
	Dec 29	Jan 09	12	29	Maintenance Outage tunnel clean
Waiau 8	Mar 15	Mar 25	11	11	Maintenance Outage tunnel clean
	Nov 25	Dec 16	22	33	Maintenance Outage tunnel clean
Waiau 9	Oct 12	Mar 03	143	143	Overhaul (Comprssr, HG, CI) Gen, Exh Dcut Repl, Blade damage
Waiau 10	Mar 04	May 27	85	85	Overhaul (Comprssr, HG, CI), Gen Exh Duct Repl
Honolulu 9	Jul 10	Sep 18	71	71	Outage (gen rewind, blr inspect, trb brgs), copper prepurchase
Capacity Purchases					
AES-Hawaii	Sep 12	Sep 25	14	14	90 MW Loss, Boiler Inspection
H-POWER	Apr 14	Apr 14	1		23 MW Loss
	Apr 15	May 15	31	32	46 MW Loss
	May 16	May 17	2	34	23 MW Loss
	Oct 29	Nov 14	17	51	23 MW Loss
	Nov 05	Nov 13	9	60	23 MW Loss
Kalaeloa CT1	Apr 17	Apr 25	9		CT1 inspection HRSG repairs
	Apr 25	May 01	7	16	180 MW Loss, CT1 B Inspection, ST Outage, CT2 Outage, Bal of Plant
	Oct 22	Oct 22	1	17	104.5 MW Loss CT1 A Inspection
Kalaeloa CT2	Apr 25	May 01	7		180 MW Loss, CT1 B Inspection, ST Outage, CT2 Outage, Bal of Plant
	Oct 15	Oct 15	1	8	104.5 MW Loss CT1 A Inspection

[1] CA-IR-43 (Revised) Docket No. 04-0113

Hawaiian Electric Company, Inc.
Generating Unit Maintenance Outage (MO) Schedule
November 12, 2004[1]

Unit	Outage Period			Total	Remarks
	Start	End	Days	(Days)	
Capacity Resources					
Kahe 1	Apr 01	Apr 06	6	6	
Kahe 2	May 01	May 01	1	1	
Kahe 3	Jan 10	Jan 18	9	9	
Kahe 4	Sep 01	Sep 01	1	1	
Kahe 5	Jul 03	Jul 07	5	5	
Kahe 6	Jan 03	Jan 09	7	7	
Waiau 3	May 02	May 10	9	9	
Waiau 4	May 22	Jun 01	11	11	
Waiau 5	Jul 11	Jul 16	6	6	
Waiau 6	May 09	May 20	12	12	
Waiau 7	Dec 10	Dec 31	22	22	
Waiau 8	Apr 11	Apr 24	14	14	
Waiau 9	Jul 18	Jul 20	3	3	
Waiau 10	Sep 12	Sep 15	4	4	
Honolulu 8	Jul 04	Jul 15	12	12	
Honolulu 9	Nov 28	Dec 14	17	17	

[1] CA-IR-501 Docket No. 04-0113

Hawaiian Electric Company, Inc.
2005 Balance of Peak Demand and Resources - HECO Update, DG In-Service July 1
April 2005 Planned/Maintenance Outage Schedule
(MW)

Capacity Requirements[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Date/Time of Peak Demand	24 - 19:00	22 - 19:00	10 - 19:00	04 - 19:00	24 - 15:00	21 - 13:00	22 - 13:00	03 - 14:00	22 - 19:00	24 - 19:00	02 - 19:00	06 - 19:00
Projected Peak Demand	1,227.0	1,201.0	1,210.0	1,203.0	1,201.0	1,231.0	1,279.0	1,286.0	1,309.0	1,316.0	1,296.0	1,250.0
Total Capacity Requirements	**1,227.0**	**1,201.0**	**1,210.0**	**1,203.0**	**1,201.0**	**1,231.0**	**1,279.0**	**1,286.0**	**1,309.0**	**1,316.0**	**1,296.0**	**1,250.0**
Capacity Resources[2]												
Kahe 1	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
Kahe 2	86.3	86.3	86.3	86.3	86.3	86.3	0[3]	0[3]	86.3	86.3	86.3	86.3
Kahe 3	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
Kahe 4	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2
Kahe 5	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7
Kahe 6	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9
Waiau 3	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2
Waiau 4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	0[3]	0[3]	0[3]
Waiau 5	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	0[3]	54.6
Waiau 6	55.6	0[3]	0[3]	0[3]	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6
Waiau 7	88.1	88.1	88.1	0[3]	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1
Waiau 8	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	0[3]
Waiau 9	0[3]	0[3]	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	0[3]	0[3]
Waiau 10	49.9	49.9	0[3]	0[3]	0[3]	0[3]	49.9	49.9	49.9	49.9	49.9	49.9
Honolulu 8	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
Honolulu 9	54.4	54.4	54.4	54.4	54.4	54.4	0[3]	0[3]	54.4	54.4	54.4	54.4
Total HECO Units	**1,156.7**	**1,101.1**	**1,103.1**	**1,015.0**	**1,158.7**	**1,158.7**	**1,067.9**	**1,067.9**	**1,208.6**	**1,162.2**	**1,055.7**	**1,022.2**
Capacity Purchases												
AES-Hawaii[1]	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	90.0	180.0	180.0	180.0
H-POWER[1]	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	23.0	46.0
Kalaeloa AC[1]	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Kalaeloa CT1[1]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Kalaeloa CT2[1]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
UtilCHP[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	14.8	14.8	14.8	14.8	14.8	14.8
Total Capacity Purchases	**435.0**	**435.0**	**435.0**	**435.0**	**435.0**	**435.0**	**449.8**	**449.8**	**359.8**	**449.8**	**426.8**	**449.8**
Total Capacity Resources	**1,591.7**	**1,536.1**	**1,538.1**	**1,450.0**	**1,593.7**	**1,593.7**	**1,517.7**	**1,517.7**	**1,568.4**	**1,612.0**	**1,482.5**	**1,472.0**
Surplus/(Deficit)	364.7	335.1	328.1	247.0	392.7	362.7	238.7	231.7	259.4	296.0	186.5	222.0
Capacity Reserve Margin (%)	29.7	27.9	27.1	20.5	32.7	29.5	18.7	18.0	19.8	22.5	14.4	17.8

[1] CA-IR-124, HECO-WP-406, Page 1 of 3
[2] CA-IR-124-b
[3] Unit out of service during Peak

Hawaiian Electric Company, Inc.
2005 Balance of Peak Demand and Resources - HECO Update (CA Case), DG In-Service October 1
November 2004 Planned/Maintenance Outage Schedule
(MW)

Capacity Requirements[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Date/Time of Peak Demand	24 - 19:00	22 - 19:00	10 - 19:00	04 - 19:00	24 - 15:00	21 - 13:00	22 - 13:00	03 - 14:00	22 - 19:00	24 - 19:00	02 - 19:00	06 - 19:00
Projected Peak Demand	1,227.0	1,201.0	1,210.0	1,203.0	1,201.0	1,231.0	1,279.0	1,286.0	1,309.0	1,316.0	1,296.0	1,250.0
Total Capacity Requirements	**1,227.0**	**1,201.0**	**1,210.0**	**1,203.0**	**1,201.0**	**1,231.0**	**1,279.0**	**1,286.0**	**1,309.0**	**1,316.0**	**1,296.0**	**1,250.0**
Capacity Resources [2]												
Kahe 1	88.2	88.2	88.2	88.2	88.2	88.2	0[3]	0[3]	88.2	88.2	88.2	88.2
Kahe 2	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3	86.3
Kahe 3	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
Kahe 4	89.2	89.2	89.2	89.2	0[3]	0[3]	89.2	89.2	89.2	89.2	89.2	89.2
Kahe 5	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7
Kahe 6	0[3]	0[3]	0[3]	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9
Waiau 3	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2
Waiau 4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	0[3]	0[3]	0[3]
Waiau 5	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6
Waiau 6	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6
Waiau 7	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1
Waiau 8	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1
Waiau 9	0[3]	0[3]	0[3]	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9
Waiau 10	49.9	49.9	49.9	49.9	0[3]	0[3]	49.9	49.9	49.9	49.9	49.9	49.9
Honolulu 8	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
Honolulu 9	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4
Total HECO Units	**1,022.8**	**1,022.8**	**1,022.8**	**1,208.6**	**1,069.5**	**1,069.5**	**1,120.4**	**1,120.4**	**1,208.6**	**1,162.2**	**1,162.2**	**1,162.2**
Capacity Purchases												
AES-Hawaii [1]	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	90.0	180.0	180.0	180.0
H-POWER[1]	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	23.0	23.0
Kalaeloa AC[1]	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Kalaeloa CT1[1]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Kalaeloa CT2[1]	90.0	90.0	90.0	0[3]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
UtilCHP[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.8	14.8	14.8
Total Capacity Purchases	**435.0**	**435.0**	**435.0**	**345.0**	**435.0**	**435.0**	**435.0**	**435.0**	**345.0**	**449.8**	**426.8**	**426.8**
Total Capacity Resources	**1,457.8**	**1,457.8**	**1,457.8**	**1,553.6**	**1,504.5**	**1,504.5**	**1,555.4**	**1,555.4**	**1,553.6**	**1,612.0**	**1,589.0**	**1,589.0**
Surplus/(Deficit)	230.8	256.8	247.8	350.6	303.5	273.5	276.4	269.4	244.6	296.0	293.0	339.0
Capacity Reserve Margin (%)	18.8	21.4	20.5	29.1	25.3	22.2	21.6	20.9	18.7	22.5	22.6	27.1

[1] CA-IR-124, HECO-WP-406, Page 1 of 3
[2] CA-IR-124-b
[3] Unit out of service during Peak

DO A-WP-306
O. 04-0113
AGE 9 OF 9

Hawaiian Electric Company, Inc.
2005 Balance of Peak Demand and Resources - HECO Update DG In-Service October 1
April 2005 Planned/Maintenance Outage Schedule
(MW)

Capacity Requirements[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Date/Time of Peak Demand	24 - 19:00	22 - 19:00	10 - 19:00	04 - 19:00	24 - 15:00	21 - 13:00	22 - 13:00	03 - 14:00	22 - 19:00	24 - 19:00	02 - 19:00	06 - 19:00
Projected Peak Demand	1,227.0	1,201.0	1,210.0	1,203.0	1,201.0	1,231.0	1,279.0	1,286.0	1,309.0	1,316.0	1,296.0	1,250.0
Total Capacity Requirements	1,227.0	1,201.0	1,210.0	1,203.0	1,201.0	1,231.0	1,279.0	1,286.0	1,309.0	1,316.0	1,296.0	1,250.0
Capacity Resources [2]												
Kahe 1	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
Kahe 2	86.3	86.3	86.3	86.3	86.3	86.3	0[3]	0[3]	86.3	86.3	86.3	86.3
Kahe 3	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
Kahe 4	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2	89.2
Kahe 5	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7	134.7
Kahe 6	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9	133.9
Waiau 3	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2	46.2
Waiau 4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	46.4	0[3]	0[3]	0[3]
Waiau 5	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	54.6	0[3]	54.6
Waiau 6	55.6	0[3]	0[3]	0[3]	55.6	55.6	55.6	55.6	55.6	55.6	55.6	55.6
Waiau 7	88.1	88.1	88.1	0[3]	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1
Waiau 8	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	0[3]
Waiau 9	0[3]	0[3]	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9	0[3]	0[3]
Waiau 10	49.9	49.9	0[3]	0[3]	0[3]	0[3]	49.9	49.9	49.9	49.9	49.9	49.9
Honolulu 8	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
Honolulu 9	54.4	54.4	54.4	54.4	54.4	54.4	0[3]	0[3]	54.4	54.4	54.4	54.4
Total HECO Units	1,156.7	1,101.1	1,103.1	1,015.0	1,158.7	1,158.7	1,067.9	1,067.9	1,208.6	1,162.2	1,055.7	1,022.2
Capacity Purchases												
AES-Hawaii [1]	180.0	180.0	180.0	180.0	180.0	180.0	180.0	180.0	90.0	180.0	180.0	180.0
H-POWER[1]	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	46.0	23.0	46.0
Kalaeloa AC[1]	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0	29.0
Kalaeloa CT1[1]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Kalaeloa CT2[1]	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
UtilCHP[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.8	14.8	14.8
Total Capacity Purchases	435.0	435.0	435.0	435.0	435.0	435.0	435.0	435.0	345.0	449.8	426.8	449.8
Total Capacity Resources	1,591.7	1,536.1	1,538.1	1,450.0	1,593.7	1,593.7	1,502.9	1,502.9	1,553.6	1,612.0	1,482.5	1,472.0
Surplus/(Deficit)	364.7	335.1	328.1	247.0	392.7	362.7	223.9	216.9	244.6	296.0	186.5	222.0
Capacity Reserve Margin (%)	29.7	27.9	27.1	20.5	32.7	29.5	17.5	16.9	18.7	22.5	14.4	17.8

[1] CA-IR-124, HECO-WP-406, Page 1 of 3
[2] CA-IR-124-b
[3] Unit out of service during Peak

Comparison of CA Output Results Using HECO DT Inputs
To HECO November Filing
(MWh)

Month	B3	B2	B1	AES	K5	W7	K4	W8	K2	K3	K1	K6	W9	W10	W6	H9	W5	H8	W4	W3	Total
Consumer Advocate Base (November Filing)																					
1	55,236	65,572	13,256	132,581	81,116	42,216	52,667	41,749	44,087	33,381	23,881	13,831	368	632	14,898	8,113	3,742	3,541	1,417	443	632,728
2	50,280	58,834	11,742	119,750	70,954	35,634	45,964	36,271	37,559	40,788	35,605	0	0	189	11,588	6,155	4,460	1,018	372	0	567,162
3	34,569	55,240	8,044	132,581	81,278	42,147	53,031	42,484	44,250	47,997	42,267	32,403	377	1,020	15,258	8,845	7,988	3,480	1,638	768	655,664
4	13,515	56,627	2,959	128,304	81,178	43,651	12,606	22,596	45,300	49,018	34,697	76,731	2,694	1,686	20,653	10,571	10,418	6,146	3,928	2,531	625,807
5	56,109	65,376	12,892	132,581	79,414	39,574	0	40,369	40,325	45,572	39,582	72,828	1,347	0	8,727	8,974	7,956	5,047	0	0	656,673
6	55,017	63,570	12,801	128,304	77,508	39,593	0	39,939	41,682	45,344	39,360	72,178	1,167	0	15,930	10,717	10,062	5,983	351	0	659,505
7	55,090	66,139	13,028	132,581	67,037	41,405	38,991	42,204	43,681	47,874	28,086	75,767	799	299	15,331	8,888	5,493	834	1,524	1,013	686,065
8	56,799	66,066	13,079	132,581	80,199	42,222	52,774	42,561	43,791	48,207	0	75,390	1,329	1,431	18,266	11,104	11,276	7,977	2,145	0	707,199
9	55,156	64,066	13,384	95,248	81,997	43,322	51,425	42,744	45,379	48,703	30,771	77,412	476	743	15,761	7,962	7,419	5,169	1,787	941	689,865
10	55,183	65,519	12,241	132,581	78,823	39,980	51,843	40,899	42,168	46,544	39,983	73,558	99	0	12,106	6,972	4,303	61	0	0	702,864
11	55,567	64,121	12,619	128,304	77,055	38,954	50,641	39,850	41,098	16,048	39,061	71,625	638	200	10,991	4,519	3,521	305	0	65	655,182
12	55,927	65,906	11,722	132,581	75,362	11,286	49,289	38,997	38,926	43,847	37,533	68,711	404	311	15,251	1,915	1,322	183	0	42	649,517
Total	598,448	757,034	137,768	1,527,976	931,921	459,985	459,232	470,664	508,248	513,322	390,827	710,434	9,698	6,510	174,760	94,736	77,959	39,744	13,161	5,803	7,888,230
$/MWh	51.77	51.74	52.87	25.82	56.33	57.81	55.60	57.09	57.15	56.44	58.24	56.68	293.10	238.05	63.03	79.04	65.92	83.54	68.23	69.78	50.97
Variable O&M					0.48720	0.46490	0.45021	0.45779	0.47777	0.44932	0.53720	0.44325	0.93681	0.85954	0.52253	0.57553	0.57154	0.61052	0.58015	0.57845	
Dispatch Cost	51.77	51.74	52.87	25.82	56.81	58.28	56.05	57.55	57.63	56.89	58.78	57.13	294.03	238.91	63.55	79.62	66.49	84.15	68.81	70.36	
HECO Base (November Filing)																					
1	55,611	65,451	13,391	132,432	79,140	41,206	50,065	42,185	41,084	31,682	24,335	12,889	48	331	15,256	4,601	5,956	2,377	8,437	6,063	632,540
2	50,927	58,878	11,825	119,616	68,754	35,119	43,213	35,927	35,771	39,550	35,632	0	0	0	12,313	1,794	8,134	693	5,518	3,166	566,830
3	35,219	55,230	8,220	132,432	79,874	42,727	51,521	44,536	42,358	45,890	42,229	31,582	41	312	15,440	3,898	9,861	1,737	7,161	5,123	655,391
4	13,528	56,496	2,958	128,160	82,434	45,961	12,635	24,239	44,910	47,344	35,150	75,965	99	946	17,886	5,401	11,508	3,935	8,836	7,077	625,468
5	56,957	65,917	13,381	132,432	79,771	40,848	0	43,134	38,833	44,355	41,033	70,148	0	0	8,280	2,713	9,624	358	4,636	3,911	656,331
6	55,536	64,080	13,342	128,160	79,635	41,576	0	43,468	40,563	44,546	40,709	71,110	0	0	14,674	1,595	9,708	235	6,385	3,861	659,183
7	55,536	66,216	13,503	132,432	67,618	41,801	38,195	44,500	41,979	46,379	28,677	71,141	64	419	14,876	3,039	7,807	659	6,530	4,490	685,861
8	57,672	66,216	13,907	132,432	83,026	43,867	53,719	45,921	42,231	46,276	0	73,399	0	90	15,824	5,034	10,925	2,423	7,842	6,255	707,059
9	55,180	64,080	14,035	98,256	81,806	43,427	50,824	45,163	42,641	45,773	30,138	72,762	9	227	15,397	5,243	10,355	2,830	5,671	5,961	689,778
10	55,179	64,725	12,797	132,432	78,646	40,179	51,084	43,328	40,266	45,143	40,865	67,535	0	22	12,830	3,687	7,924	884	0	5,112	702,638
11	55,502	63,988	13,054	128,160	75,627	38,224	48,867	40,680	38,929	15,996	39,468	65,565	1	71	13,009	3,156	8,122	1,357	0	5,238	655,014
12	56,177	65,937	12,131	132,432	74,896	11,130	47,406	39,518	37,822	43,872	38,132	64,748	0	79	11,106	1,204	7,486	1,347	84	3,792	649,299
Total	603,024	757,214	142,544	1,529,376	931,227	466,065	447,529	492,599	487,387	496,806	396,368	676,844	262	2,497	166,891	41,365	107,410	18,835	61,100	60,049	7,885,392
Dispatch Cost	52.88	52.88	52.88	25.95	57.20	58.17	56.78	58.55	57.63	56.91	58.29	52.05	188.86	197.35	63.30	74.38	66.29	70.68	68.45	70.94	
Difference	(4,576)	(180)	(4,776)	(1,400)	694	(6,080)	11,703	(21,935)	20,861	16,516	(5,541)	33,590	9,436	4,013	7,869	53,371	(29,451)	20,909	(47,939)	(54,246)	2,838

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Consumer Advocate BTU per KWh for each of HECO Units
(Based on Using HECO DT Inputs)

Month	B3	B2	B1	AES	K5	W7	K4	W8	K2	K3	K1	K6	W9	W10	W6	H9	W5	H8	W4	W3	Total
CA																					
1	8,566	8,560	8,735	17,332	10,053	10,312	9,931	10,194	10,196	10,089	10,382	10,119	30,238	24,564	11,213	12,737	11,794	13,460	12,251	12,590	11,432
2	8,588	8,579	8,735	17,332	10,075	10,348	9,955	10,217	10,226	10,113	10,427	0	0	24,564	11,274	12,737	11,794	13,460	12,267	0	11,423
3	8,558	8,548	8,735	17,332	10,046	10,318	9,919	10,187	10,193	10,071	10,379	10,077	30,238	24,564	11,171	12,737	11,751	13,460	12,124	12,331	11,493
4	8,535	8,532	8,735	17,332	10,022	10,290	9,879	10,184	10,164	10,051	10,350	10,084	30,238	24,564	11,185	12,736	11,719	13,460	12,127	12,383	11,703
5	8,576	8,569	8,735	17,332	10,068	10,342	0	10,209	10,217	10,098	10,419	10,147	30,238	0	11,352	12,737	11,794	13,460	0	0	11,440
6	8,559	8,555	8,735	17,332	10,060	10,329	0	10,192	10,207	10,077	10,400	10,127	30,238	0	11,311	12,737	11,794	13,460	12,267	0	11,409
7	8,537	8,536	8,735	17,332	10,051	10,323	9,921	10,182	10,194	10,062	10,386	10,110	30,238	24,564	11,254	12,737	11,763	13,460	12,183	12,514	11,330
8	8,540	8,539	8,735	17,332	10,057	10,322	9,919	10,187	10,205	10,069	0	10,118	30,238	24,564	11,259	12,737	11,781	13,460	12,237	0	11,376
9	8,534	8,533	8,735	17,613	10,017	10,286	9,888	10,159	10,158	10,039	10,327	10,077	30,238	24,564	11,120	12,737	11,765	13,460	12,202	12,620	10,972
10	8,533	8,532	8,735	17,332	10,071	10,342	9,932	10,196	10,220	10,074	10,414	10,137	30,238	0	11,244	12,737	11,794	13,460	0	0	11,262
11	8,531	8,531	8,735	17,332	10,063	10,338	9,925	10,191	10,213	10,074	10,405	10,129	30,238	24,564	11,218	12,737	11,793	13,460	0	12,650	11,305
12	8,548	8,545	8,735	17,332	10,101	10,350	9,969	10,232	10,266	10,121	10,466	10,183	30,238	24,564	11,509	12,737	11,794	13,460	0	12,715	11,369
Total	8,551	8,547	8,735	17,350	10,056	10,322	9,927	10,194	10,204	10,077	10,398	10,120	30,238	24,564	11,254	12,737	11,773	13,460	12,182	12,459	11,372

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CA Output Using HECO DT Inputs Compared to CA DT Position
(MWh)

Month	B3	B2	B1	AES	K5	W7	K4	W8	K2	K3	K1	K6	W9	W10	W6	H9	W5	H8	W4	W3	Total
Consumer Advocate DT Position																					
1	55,285	65,620	16,201	132,581	73,588	35,293	53,089	46,153	48,756	38,610	25,416	13,426	395	621	11,278	7,675	3,887	3,381	1,488	687	633,429
2	50,425	58,979	14,448	119,750	61,882	29,565	46,338	38,750	42,133	47,862	36,945	0	0	189	8,741	5,785	4,595	971	369	0	567,727
3	34,600	55,271	10,069	132,581	72,957	35,214	53,592	46,047	48,226	55,101	44,513	31,635	395	1,120	11,476	8,530	8,591	3,381	1,748	1,067	656,116
4	13,533	56,657	3,999	128,304	75,528	38,206	12,864	25,018	48,993	55,666	37,294	75,246	2,523	1,774	15,865	10,616	11,612	5,578	4,400	2,171	625,846
5	56,215	65,482	16,483	132,581	71,153	33,007	0	43,574	46,155	53,719	41,521	68,843	1,374	0	6,701	8,312	7,677	4,758	0	0	657,554
6	55,144	63,698	17,042	128,304	69,980	32,989	0	43,758	46,672	52,914	41,887	68,915	1,185	0	12,057	9,631	9,938	5,962	343	0	660,419
7	55,154	66,202	17,243	132,581	59,652	34,979	39,578	45,834	48,808	55,642	29,547	72,495	853	455	11,474	7,924	5,603	692	1,137	1,044	686,899
8	56,986	66,252	18,033	132,581	73,079	36,796	53,503	47,031	48,372	55,534	0	73,937	1,140	1,664	14,150	10,072	12,087	6,918	517	0	708,654
9	55,242	64,152	17,800	94,268	75,714	36,360	52,447	47,838	49,297	56,153	32,907	75,376	458	821	10,997	7,118	7,931	3,950	1,700	1,189	691,715
10	55,201	65,537	17,308	132,581	72,053	33,611	52,539	44,604	47,632	54,147	42,554	70,368	90	0	7,851	5,019	2,597	58	0	0	703,750
11	55,450	64,003	17,292	128,304	69,632	33,045	51,289	43,615	45,906	18,345	42,054	69,092	700	244	9,503	5,108	5,508	506	0	197	659,794
12	56,064	66,044	16,269	132,581	65,046	9,469	49,872	40,882	44,438	52,225	39,032	63,660	449	355	12,526	1,788	1,333	233	0	63	652,329
Total	599,300	757,898	182,187	1,526,996	840,264	388,533	465,111	513,104	565,388	595,917	413,670	682,993	9,564	7,242	132,620	87,579	81,359	36,388	11,703	6,418	7,904,232
$/MWh	73.80	73.76	75.41	39.96	87.81	93.57	87.20	89.97	87.20	84.89	88.86	88.36	409.91	333.00	106.33	118.94	104.39	112.23	105.50	104.20	77.69
Variable O&M					0.48720	0.46490	0.45021	0.45779	0.47777	0.44932	0.5372	0.44325	0.93681	0.85954	0.52253	0.57553	0.57154	0.61052	0.58015	0.57845	
Dispatch Cost	73.80	73.76	75.41	39.96	88.30	94.04	87.65	90.43	87.68	85.34	89.40	88.81	410.85	333.86	106.85	119.51	104.97	112.85	106.08	104.78	
Consumer Advocate Base (Using HECO DT November 2004 Filing)																					
1	55,236	65,572	13,256	132,581	81,116	42,216	52,667	41,749	44,087	33,381	23,881	13,831	368	632	14,898	8,113	3,742	3,541	1,417	443	632,728
2	50,280	58,834	11,742	119,750	70,954	35,634	45,964	36,271	37,559	40,788	35,605	0	0	189	11,588	6,155	4,460	1,018	372	0	567,162
3	34,569	55,240	8,044	132,581	81,278	42,147	53,031	42,484	44,250	47,997	42,267	32,403	377	1,020	15,258	8,845	7,988	3,480	1,638	768	655,664
4	13,515	56,627	2,959	128,304	81,178	43,651	12,606	22,596	45,300	49,018	34,697	76,731	2,694	1,686	20,653	10,571	10,418	6,146	3,928	2,531	625,807
5	56,109	65,376	12,892	132,581	79,414	39,574	0	40,369	40,325	45,572	39,582	72,828	1,347	0	8,727	8,974	7,956	5,047	0	0	656,673
6	55,017	63,570	12,801	128,304	77,508	39,593	0	39,939	41,682	45,344	39,360	72,178	1,167	0	15,930	10,717	10,062	5,983	351	0	659,505
7	55,090	66,139	13,028	132,581	67,037	41,405	38,991	42,204	43,681	47,874	28,086	75,767	799	299	15,331	8,888	5,493	834	1,524	1,013	686,065
8	56,799	66,066	13,079	132,581	80,199	42,222	52,774	42,561	43,791	48,207	0	75,390	1,329	1,431	18,266	11,104	11,276	7,977	2,145	0	707,199
9	55,156	64,066	13,384	95,248	81,997	43,322	51,425	42,744	45,379	48,703	30,771	77,412	476	743	15,761	7,962	7,419	5,169	1,787	941	689,865
10	55,183	65,519	12,241	132,581	78,823	39,980	51,843	40,899	42,168	46,544	39,983	73,558	99	0	12,106	6,972	4,303	61	0	0	702,864
11	55,567	64,121	12,619	128,304	77,055	38,954	50,641	39,850	41,098	16,048	39,061	71,625	638	200	10,991	4,519	3,521	305	0	65	655,182
12	55,927	65,906	11,722	132,581	75,362	11,286	49,289	38,997	38,926	43,847	37,533	68,711	404	311	15,251	1,915	1,322	183	0	42	649,517
Total	598,448	757,034	137,768	1,527,976	931,921	459,985	459,232	470,664	508,248	513,322	390,827	710,434	9,698	6,510	174,760	94,736	77,959	39,744	13,161	5,803	7,888,230
Dispatch Cost	51.77	51.74	52.87	25.82	56.33	57.81	55.60	57.09	57.15	56.44	58.24	56.68	293.10	238.05	63.03	79.04	65.92	83.54	68.23	69.78	50.97
Difference	852	864	44,418	(980)	(91,657)	(71,452)	5,879	42,440	57,140	82,595	22,843	(27,441)	(135)	732	(42,140)	(7,157)	3,401	(3,356)	(1,458)	615	16,003

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Consumer Advocate MBTU for each of HECO Units

Month	B3	B2	B1	AES	K5	W7	K4	W8	K2	K3	K1	K6	W9	W10	W6	H9	W5	H8	W4	W3	Total
Consumer Advocate DT Position																					
1	473,416	561,577	141,507	2,297,956	745,451	380,867	534,560	478,946	490,442	378,511	260,454	136,947	11,948	15,255	138,173	100,166	47,193	41,570	18,273	8,258	7,261,471
2	432,623	505,584	126,199	2,075,573	628,258	320,687	467,675	403,599	424,799	469,894	379,816	0	0	4,631	108,168	75,714	55,997	11,941	4,572	0	6,495,728
3	296,029	472,351	87,952	2,297,956	739,072	380,237	538,891	477,601	485,286	539,483	456,056	321,419	11,948	27,513	140,526	111,012	103,438	41,505	21,289	12,780	7,562,344
4	115,459	483,303	34,928	2,223,828	762,841	410,474	128,730	258,782	491,693	543,526	380,857	764,118	76,303	43,586	192,085	136,498	137,446	68,319	53,127	25,952	7,331,854
5	481,771	560,812	143,970	2,297,956	721,511	357,507	0	453,122	464,645	527,044	426,241	703,840	41,546	0	83,147	108,821	94,169	58,508	0	0	7,524,609
6	471,613	544,574	148,858	2,223,828	709,069	356,533	0	454,346	469,505	518,569	429,434	703,274	35,843	0	149,019	126,082	121,262	73,315	4,256	0	7,539,380
7	470,688	564,929	150,612	2,297,956	604,508	377,743	398,157	475,361	490,857	544,618	302,821	738,865	25,796	11,169	140,708	103,232	67,115	8,491	13,874	12,526	7,800,026
8	486,181	565,222	157,512	2,297,956	740,170	396,737	537,604	487,572	486,719	543,533	0	753,237	34,486	40,862	172,093	130,614	144,783	85,032	6,263	0	8,066,574
9	471,206	547,207	155,477	1,659,667	764,682	390,730	525,337	494,134	494,516	548,350	335,758	765,292	13,849	20,158	133,252	92,292	94,110	48,492	20,801	14,492	7,589,802
10	470,964	559,125	151,178	2,297,956	730,349	363,615	528,802	463,294	479,353	530,582	436,393	718,135	2,715	0	96,988	65,688	31,505	716	0	0	7,927,358
11	473,379	546,340	151,035	2,223,828	705,536	357,179	516,332	452,942	461,848	180,053	431,324	705,229	21,180	5,993	117,022	66,766	66,702	6,218	0	2,385	7,491,292
12	478,863	563,985	142,101	2,297,956	662,166	102,666	503,839	426,956	449,191	512,982	402,304	653,103	13,577	8,717	155,701	23,411	16,304	2,866	0	766	7,417,453
Total	5,122,191	6,475,009	1,591,331	26,492,413	8,513,611	4,194,976	4,679,926	5,326,655	5,688,856	5,837,147	4,241,458	6,963,457	289,190	177,884	1,626,882	1,140,296	980,023	446,972	142,454	77,160	90,007,892
Consumer Advocate Base (Using HECO DT November 2004 Filing)																					
1	473,144	561,305	115,789	2,297,956	815,431	435,341	523,018	425,574	449,525	336,783	247,931	139,960	11,133	15,527	167,047	103,336	44,140	47,660	17,364	5,579	7,233,541
2	431,791	504,751	102,565	2,075,573	714,865	368,734	457,559	370,585	384,094	412,498	371,241	0	0	4,631	130,644	78,393	52,598	13,696	4,558	0	6,478,775
3	295,851	472,173	70,267	2,297,956	816,516	434,874	525,999	432,794	451,025	483,376	438,682	326,520	11,405	25,062	170,445	112,655	93,863	46,839	19,855	9,472	7,535,629
4	115,351	483,122	25,847	2,223,828	813,582	449,157	124,537	230,123	460,422	492,675	359,096	773,778	81,462	41,406	230,996	134,632	122,084	82,721	47,631	31,344	7,323,795
5	481,175	560,216	112,609	2,297,956	799,515	409,294	0	412,111	411,997	460,205	412,412	738,974	40,731	0	99,062	114,300	93,830	67,930	0	0	7,512,317
6	470,882	543,843	111,812	2,223,828	779,747	408,943	0	407,064	425,463	456,934	409,328	730,983	35,300	0	180,192	136,502	118,675	80,530	4,304	0	7,524,329
7	470,312	564,554	113,794	2,297,956	673,789	427,420	386,840	429,718	445,283	481,721	291,714	765,998	24,167	7,355	172,538	113,203	64,611	11,230	18,568	12,682	7,773,453
8	485,090	564,131	114,246	2,297,956	806,591	435,802	523,477	433,576	446,866	485,409	0	762,798	40,188	35,141	205,649	141,436	132,836	107,373	26,249	0	8,044,812
9	470,701	546,702	116,908	1,677,632	821,338	445,614	508,495	434,234	460,967	488,950	317,779	780,048	14,392	18,251	175,256	101,417	87,283	69,573	21,804	11,871	7,569,215
10	470,859	559,020	106,924	2,297,956	793,805	413,492	514,920	416,992	430,948	468,885	416,366	745,652	2,987	0	136,119	88,808	50,748	822	0	0	7,915,304
11	474,061	547,022	110,225	2,223,828	775,400	402,686	502,629	406,093	419,747	161,671	406,432	725,509	19,279	4,903	123,297	57,561	41,526	4,109	0	817	7,406,794
12	478,060	563,181	102,388	2,297,956	761,240	116,814	491,354	399,032	399,623	443,766	392,814	699,692	12,219	7,627	175,530	24,395	15,594	2,465	0	532	7,384,282
Total	5,117,276	6,470,020	1,203,374	26,510,378	9,371,818	4,748,170	4,558,829	4,797,898	5,185,962	5,172,872	4,063,795	7,189,912	293,263	159,905	1,966,774	1,206,637	917,788	534,946	160,334	72,296	89,702,246
Differen	4,916	4,989	387,957	(17,965)	(858,206)	(553,194)	121,097	528,757	502,894	664,275	177,664	(226,455)	(4,073)	17,979	(339,891)	(66,342)	62,235	(87,975)	(17,880)	4,864	305,645

Consumer Advocate Fuel Cost ($) for each of HECO Units and Purchased Energy Cost

Month	B3	B2	B1	AES	K5	W7	K4	W8	K2	K3	K1	K6	W9	W10	W6	H9	W5	H8	W4	W3	Total
Consumer Advocate Position																					
1	4,087,506	4,848,698	1,221,701	5,292,816	6,460,650	3,300,894	4,632,801	4,150,971	4,250,473	3,280,446	2,257,319	1,186,881	161,964	206,808	1,197,616	914,994	408,996	379,824	158,377	71,571	48,471,306
2	3,735,293	4,365,245	1,089,546	4,780,608	5,444,999	2,779,321	4,053,152	3,497,978	3,681,567	4,072,439	3,291,799	0	0	62,781	937,561	691,628	485,297	109,100	39,626	0	43,117,940
3	2,555,933	4,078,317	759,333	5,292,816	6,405,351	3,295,435	4,670,340	4,139,308	4,205,802	4,675,543	3,952,588	2,785,663	161,964	372,993	1,217,998	1,014,079	896,453	379,225	184,519	110,767	51,154,427
4	996,879	4,172,887	301,548	5,122,080	6,611,319	3,557,480	1,115,643	2,242,815	4,261,357	4,710,584	3,300,875	6,622,407	1,034,361	590,880	1,664,850	1,246,925	1,191,225	624,222	460,467	224,931	50,053,735
5	4,159,651	4,842,099	1,242,959	5,292,816	6,253,214	3,098,443	0	3,927,191	4,026,903	4,567,731	3,694,159	6,100,097	563,193	0	720,700	994,050	816,097	534,590	0	0	50,833,893
6	4,071,942	4,701,894	1,285,162	5,122,080	6,145,349	3,089,988	0	3,937,790	4,069,025	4,494,297	3,721,832	6,095,151	485,892	0	1,291,642	1,151,730	1,050,914	669,874	36,886	0	51,421,448
7	4,063,963	4,877,651	1,300,296	5,292,816	5,239,163	3,273,825	3,450,651	4,119,897	4,254,091	4,720,049	2,624,516	6,403,599	349,695	151,413	1,219,588	943,006	581,656	77,577	120,251	108,567	53,172,270
8	4,197,727	4,880,175	1,359,871	5,292,816	6,414,868	3,438,426	4,659,172	4,225,711	4,218,216	4,710,648	0	6,528,109	467,487	553,950	1,491,594	1,193,148	1,254,775	776,931	54,284	0	55,717,908
9	4,068,440	4,724,640	1,342,300	3,822,756	6,627,294	3,386,384	4,552,839	4,282,569	4,285,812	4,752,390	2,910,001	6,632,583	187,731	273,282	1,154,929	843,077	815,629	443,064	180,285	125,603	55,411,608
10	4,066,345	4,827,537	1,305,182	5,292,816	6,329,798	3,151,365	4,582,889	4,015,322	4,154,386	4,598,394	3,782,141	6,223,960	36,810	0	840,652	600,039	273,038	6,546	0	0	54,087,220
11	4,087,197	4,717,149	1,303,949	5,122,080	6,114,746	3,095,597	4,474,812	3,925,603	4,002,666	1,560,467	3,738,203	6,112,091	287,118	81,246	1,014,286	609,891	578,065	56,810	0	20,674	50,902,650
12	4,134,541	4,869,485	1,226,822	5,292,816	5,738,902	889,785	4,366,590	3,700,426	3,892,954	4,445,882	3,486,670	5,660,368	184,050	118,176	1,349,591	213,850	141,292	26,184	0	6,638	49,745,022
Total	44,225,417	55,905,777	13,738,669	61,019,316	73,785,653	36,356,943	40,558,889	46,165,581	49,303,252	50,588,870	36,760,103	60,350,909	3,920,265	2,411,529	14,101,007	10,416,417	8,493,437	4,083,947	1,234,695	668,751	614,089,427
Consumer Advocate Base (Using HECO DT November 2004 Filing)																					
1	2,864,359	3,398,075	700,847	3,420,168	4,567,296	2,438,313	2,929,539	2,383,574	2,517,720	1,886,297	1,388,652	783,901	107,912	150,480	935,594	641,277	247,160	295,800	97,243	31,248	31,785,455
2	2,614,014	3,055,710	620,792	3,089,184	4,004,000	2,065,229	2,562,870	2,075,581	2,151,269	2,310,365	2,079,290	0	0	44,880	731,715	486,486	294,520	85,000	25,524	0	28,296,429
3	1,791,048	2,858,480	425,302	3,420,168	4,573,378	2,435,703	2,946,225	2,424,032	2,526,109	2,707,329	2,457,039	1,828,837	110,544	242,880	954,633	699,111	525,602	290,700	111,203	53,053	33,381,376
4	698,322	2,924,762	156,440	3,309,840	4,556,942	2,515,708	697,556	1,288,885	2,578,723	2,759,375	2,011,288	4,333,920	789,600	401,280	1,293,761	835,496	683,649	513,400	266,766	175,554	32,791,267
5	2,912,977	3,391,481	681,584	3,420,168	4,478,135	2,292,401	0	2,308,162	2,307,549	2,577,580	2,309,894	4,138,944	394,800	0	554,821	709,317	525,400	421,600	0	0	33,424,813
6	2,850,656	3,292,352	676,767	3,309,840	4,367,416	2,290,431	0	2,279,907	2,382,958	2,559,245	2,292,630	4,094,214	342,160	0	1,009,204	847,098	664,520	499,800	24,106	0	33,783,304
7	2,847,211	3,417,735	688,770	3,420,168	3,773,924	2,393,939	2,166,731	2,406,791	2,493,975	2,698,067	1,633,869	4,290,308	234,248	71,280	966,347	702,513	361,804	69,700	103,993	71,035	34,812,408
8	2,936,671	3,415,175	691,494	3,420,168	4,517,771	2,440,873	2,932,067	2,428,400	2,502,821	2,718,707	0	4,272,399	389,536	340,560	1,151,792	877,716	743,835	666,400	147,005	0	36,593,390
9	2,849,560	3,309,660	707,625	2,496,979	4,600,400	2,495,841	2,848,171	2,432,104	2,581,786	2,738,541	1,779,869	4,369,026	139,496	176,880	981,578	629,370	488,754	431,800	122,115	66,493	36,246,048
10	2,850,519	3,384,235	647,173	3,420,168	4,446,162	2,315,919	2,884,141	2,335,521	2,413,692	2,626,176	2,332,026	4,176,358	28,952	0	762,370	551,124	284,164	5,100	0	0	35,463,800
11	2,869,903	3,311,599	667,154	3,309,840	4,343,070	2,255,389	2,815,286	2,274,476	2,350,948	905,510	2,276,387	4,063,531	186,872	47,520	690,563	357,210	232,524	25,500	0	4,575	32,987,857
12	2,894,119	3,409,431	619,705	3,420,168	4,263,716	654,255	2,752,118	2,234,896	2,238,257	2,485,508	2,200,112	3,918,901	118,440	73,920	983,072	151,389	87,320	15,300	0	2,980	32,523,607
Total	30,979,359	39,168,695	7,283,653	39,456,859	52,492,210	26,594,001	25,534,704	26,872,329	29,045,807	28,972,700	22,761,056	40,270,339	2,842,560	1,549,680	11,015,450	7,488,107	5,139,252	3,320,100	897,955	404,938	402,089,754
Differen	13,246,058	16,737,082	6,455,016	21,562,457	21,293,443	9,762,942	15,024,185	19,293,252	20,257,445	21,616,170	13,999,047	20,080,570	1,077,705	861,849	3,085,557	2,928,310	3,354,185	763,847	336,740	263,813	211,999,673

Consumer Advocate BTU per KWh for each of HECO Units - CA DT Position

Month	B3	B2	B1	AES	K5	W7	K4	W8	K2	K3	K1	K6	W9	W10	W6	H9	W5	H8	W4	W3	Total
1	8,563	8,558	8,735	17,332	10,130	10,792	10,069	10,377	10,059	9,803	10,248	10,200	30,238	24,564	12,252	13,051	12,141	12,296	12,281	12,018	11,464
2	8,579	8,572	8,735	17,332	10,153	10,847	10,093	10,416	10,082	9,818	10,281	0	0	24,564	12,374	13,088	12,186	12,297	12,383	0	11,442
3	8,556	8,546	8,735	17,332	10,130	10,798	10,055	10,372	10,063	9,791	10,245	10,160	30,238	24,564	12,245	13,014	12,041	12,276	12,176	11,978	11,526
4	8,532	8,530	8,735	17,332	10,100	10,744	10,007	10,344	10,036	9,764	10,212	10,155	30,238	24,564	12,107	12,858	11,837	12,248	12,075	11,957	11,715
5	8,570	8,564	8,735	17,332	10,140	10,831	0	10,399	10,067	9,811	10,266	10,224	30,238	0	12,408	13,092	12,266	12,297	0	0	11,443
6	8,552	8,549	8,735	17,332	10,132	10,808	0	10,383	10,060	9,800	10,252	10,205	30,238	0	12,360	13,091	12,201	12,297	12,409	0	11,416
7	8,534	8,533	8,735	17,332	10,134	10,799	10,060	10,371	10,057	9,788	10,249	10,192	30,238	24,564	12,263	13,027	11,978	12,266	12,197	12,001	11,355
8	8,532	8,531	8,735	17,332	10,128	10,782	10,048	10,367	10,062	9,787	0	10,188	30,238	24,564	12,162	12,968	11,978	12,291	12,116	0	11,383
9	8,530	8,530	8,735	17,606	10,100	10,746	10,017	10,329	10,031	9,765	10,203	10,153	30,238	24,564	12,117	12,966	11,866	12,277	12,234	12,189	10,972
10	8,532	8,531	8,735	17,332	10,136	10,818	10,065	10,387	10,064	9,799	10,255	10,205	30,238	0	12,353	13,087	12,133	12,297	0	0	11,264
11	8,537	8,536	8,735	17,332	10,132	10,809	10,067	10,385	10,061	9,815	10,256	10,207	30,238	24,564	12,314	13,071	12,110	12,294	0	12,081	11,354
12	8,541	8,540	8,735	17,332	10,180	10,842	10,103	10,444	10,108	9,823	10,307	10,259	30,238	24,564	12,430	13,092	12,228	12,297	0	12,155	11,371
Total	8,547	8,543	8,735	17,349	10,132	10,797	10,062	10,381	10,062	9,795	10,253	10,195	30,238	24,564	12,267	13,020	12,046	12,284	12,172	12,023	11,387

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DIRECT TESTIMONY AND EXHIBITS

OF

DAVID C. PARCELL

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: RATE OF RETURN

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DIRECT TESTIMONY OF DAVID C. PARCELL

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, VA 23219.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. The majority of my consulting experience has involved the provision of cost of capital testimony in public utility ratemaking proceedings. I have previously testified in over 350 utility proceedings before more than 30 regulatory agencies in the United States and Canada. In connection with these proceedings, I filed testimony in Maui Electric Company, Limited's ("MECO") last three rate proceedings (Docket Nos. 94-0345, 96-0040 and 97-0346 – the cost of capital issues in the first two of cases were settled prior to hearing and I testified in the third case) and I filed testimony and testified in Hawaii Electric Light Company's ("HELCO") last two litigated rate proceedings (Docket Nos. 94-0140 and 99-0207). I also filed testimony and testified in a 1997 rate proceeding involving Young Brothers, Ltd. (Docket No. 96-0483) and I filed testimony in the 2001 rate proceeding of The Gas Company (Docket No. 00-0309 - the cost of capital issues in that proceeding were settled prior to hearing). CA-400 provides a more complete description of my background and experience.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Division of Consumer Advocacy ("Consumer Advocate" or "CA") to evaluate the cost of capital aspects of the current filing of Hawaiian Electric Company, Inc. ("HECO" or "Company"). I have performed independent studies and will provide a recommendation of the current cost of capital for HECO. In addition, since HECO is a subsidiary of Hawaiian Electric Industries, Inc. ("HEI"), I have also evaluated this entity in my analyses.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared 15 exhibits, identified as CA-400 through CA-414. These exhibits were prepared either by me or under my direction. The information contained in these exhibits is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY.

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendations for HECO is as follows:

	Percent	Cost	Return
Short-term Debt	3.25%	3.50%	0.11%
Long-term Debt	36.81%	6.25%	2.30%
Hybrid Securities	2.37%	7.55%	0.18%
Preferred Stock	1.78%	5.54%	0.10%
Common Equity	55.79%	8.5 – 10.0%	4.74 – 5.58%
Total Cost of Capital	100.00%		7.43 - 8,27%
Recommendation			7.85%

These recommendations may be revised at the time of the evidentiary hearing to incorporate more current financial data.

The Company is requesting a total cost of capital of 9.08 percent, which incorporates a cost of common equity of 11.50 percent.[1]

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS.

A. This proceeding is concerned with the regulated electric utility operations of HECO, relative to its 2005 test year. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. HECO's proposed capital structure is its 2003 actual capital structure adjusted for expected changes in 2004 and 2005. I essentially use the same capital structure

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[1] HECO 2101, as updated.

proposed by HECO, but I do not include the "Lease Obligation" component proposed by HECO.[2]

The second step in a cost of capital calculation is a determination of the embedded cost rates of debt, preferred stock, and hybrid securities. I have used the same rates proposed by the Company, but I may revise them at the time of the evidentiary hearing to reflect more current information.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for HECO. Each of these methodologies is applied to two groups of comparison companies selected as having similar risk and operating characteristics to HECO (See Section VII - Selection of Comparison Groups). The results of these three methodologies are:

Discounted Cash Flow	8½%
Capital Asset Pricing Model	9.4-9.8%
Comparable Earnings	10%

Based upon these findings, my recommendation of a fair cost of common equity for HECO is in the range of 8.5 percent to 10.0 percent, with a mid-point of 9.25 percent. My recommended range approximates the upper end results of each of the ranges developed in my three methodologies. I recognize that the Hawaii Commission has been reluctant to incorporate the results of

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[2] The justification for not including the "Lease Obligation" in the capital structure will be addressed by Mr. Steve Carver in CA-T-2.

comparable earnings analyses in its findings for public utilities under its jurisdiction; however, I note that my recommendation would be 8.5 percent to 10.0 percent in the absence of my comparable earnings analysis and I have again performed it to corroborate the results of my DCF and CAPM analyses.

Combining these three steps into a weighted cost of capital results in an overall rate of return of 7.43 to 8.27 percent, with a mid-point of 7.85 percent. I recommend the 7.85 percent mid-point be used to establish HECO's fair rate of return.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES.

Q. WHAT IS YOUR UNDERSTANDING OF THE ECONOMIC AND LEGAL PRINCIPLES WHICH UNDERLIE THE CONCEPT OF A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Cost of service rates for regulated public utilities has traditionally been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers. The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, the fair rate of return is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to incorporate the financial concepts of financial integrity, capital attraction, and comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two U.S. Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the

> **exercise of a fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business** undertakings which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.[3] [Emphasis added.]

Based on my understanding, this decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. The Commission also noted that the required level of returns have changed over time, as well as an underlying assumption that the utility be operated in an efficient manner. The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests**. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments**

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[3] Id. at 692-693.

> in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**.[4] [Emphasis added.]

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

Three economic and financial parameters identified in the Bluefield and Hope decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the "opportunity cost" principle of economics, which holds that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely that it is intended to act as a surrogate for competition.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is

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4 Id. at 603.

the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY FOR HECO?

A. I have utilized three methodologies to determine HECO's cost of common equity. These are the DCF, CAPM, and CE methods. The results of each of these methodologies will be described in my testimony.

IV. <u>GENERAL ECONOMIC CONDITIONS.</u>

Q. WHAT IS THE IMPORTANCE OF ECONOMIC AND FINANCIAL CONDITIONS IN DETERMINING THE COST OF CAPITAL?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by economic and financial conditions. At any given time, each of the following factors has direct and significant influences on the costs of capital: the level of economic activity, the stage of the business cycle, the level of inflation, and expected economic conditions. My understanding is that this position is consistent with the Supreme Court Bluefield decision which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to the present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to-date, and thus makes it possible to assess changes in long-term trends. A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The most recent complete cycle began with an expansion in April of 1991 and ended in the fourth quarter of 2001, constituting a length of more than ten and one-half years. Recently, the economy slowed considerably in late 2000 and 2001 and was in a recession during three quarters of 2001, notwithstanding the Federal Reserve lowering interest rates eleven times in 2001 (as well as twice in 2003) in an aggressive effort to create a soft landing and avoid a recession. The events of September 11, 2001 further damaged the U.S. economy.

This cycle and the two prior complete cycles cover the following periods:

Business Cycle	Expansion Period	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001

The expansion phase of the recent cycle well surpassed the average length of expansions in the post-World War II era (i.e., about five years). The 1982-1990 expansion (seven years, eight months) was the previous longest peacetime expansion of this era.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. CA-401 shows several sets of economic data. Page 1 contains general macroeconomic statistics while pages 2 and 3 contain financial market statistics. Page 1 of CA-401 shows that growth in the initial stage of the current cycle has been somewhat slower than the typical initial recovery period and economic growth has actually slowed in 2004. This is indicated by the growth in the real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate.

The rate of inflation is also shown on page 1 of CA-401, reflected in the Consumer Price Index ("CPI"). The CPI rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.3 percent rate of inflation in 2004 was slightly higher than the most recent years, but was well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Page 2 of CA-401 shows several series of interest rates. Rates rose sharply in 1975-1981 when the inflation rate was high and rising. Rates then fell substantially throughout the remainder of the 1980s and into the 1990s. During the recent business cycle, long-term rates remained relatively stable, in comparison to the prior cycles, and currently are generally lower than at any time during the prior three cycles.

This low level of interest rates, in conjunction with the apparent strengthening of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has recently increased short-term interest rates on several occasions, although each by only a small 0.25 percent level, in an attempt to insure that any perceived inflationary expectations do not stifle continued economic growth. Nevertheless, the economic recovery to-date has not resulted in a pronounced increase in rates and, even if rates were to increase moderately, they would still remain well below historical levels.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Page 3 of CA-401 shows several series of common stock prices and ratios. These generally indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. Over the past four years, however, stock prices have been volatile and have declined substantially from their highs reached in 1999 and early 2000. Share prices have finally increased somewhat in 2003 and 2004.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that the cost of equity models, such as the DCF, currently produce returns that are lower than was the case in prior years.

V. <u>HECO'S OPERATIONS AND BUSINESS RISKS.</u>

Q. PLEASE DESCRIBE HECO AND ITS OPERATIONS.

A. HECO is an operating electric utility which is in the business of generating, purchasing, transmitting, distributing, and selling electric energy. Its service area is the island of Oahu. The Company owns HELCO and MECO. Combined, these three companies comprise the electric utility operations of HEI, which provide electricity to 93 percent of Hawaii's residents.[5]

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5 See HEI 2004 Annual Report, page 16.

The Oahu operations of HECO (i.e., HECO as an operating electric utility exclusive of HELCO and MECO) account for approximately 68 percent of HECO's consolidated customers and electric sales revenues.[6] As such, the Oahu segment of HECO is seen to be the most dominant portion of HECO's operations.

Q. PLEASE BRIEFLY DESCRIBE HEI'S BUSINESS OPERATIONS.

A. HEI was incorporated in 1981 and, as part of a corporate restructuring in 1983, became the parent company of HECO. HEI is a holding company with subsidiaries engaged in the provision of electric energy (i.e., HECO, HELCO, and MECO), financial services (i.e., American Savings Bank, F.S.B.), and other businesses.

The major operations of HEI can be summarized as follows (2004 figures in $000s):

	Revenues	Operating Income	Capital Expenditures	Assets
Electric Utility	$1,550,671 81%	$173,903 64%	$201,236 94%	$2,770,985 29%
Savings Bank	$364,284 19%	$104,974 39%	$13,085 6%	$6,766,505 70%
Other	$9,102 0%	-$7,917 -3%	$333 0%	$73,137 1%

Source: HEI 2004 Form 10-K, pages 95 and 110.
Note: Percentages do not reflect the elimination of the holding company and inter-company transactions.

6 See HEI 2004 Form 10-K, page 2.

Q. WHAT HAS BEEN THE TREND IN HEI'S BUSINESS SEGMENT RATIOS IN RECENT YEARS?

A. This is shown on CA-402. As indicated, the electric utility operations have remained dominant in terms of revenues, operating income and capital expenditures. The "other" operations have remained small and, as a group, unprofitable.

Q. PLEASE DESCRIBE THE NATURE OF HEI'S ELECTRIC ENERGY OPERATIONS.

A. HECO constitutes HEI's electric energy operations, which are carried out through its own operations (i.e., Oahu) and the operations of HELCO and MECO, which it owns. As noted above, the electric energy operations account for about 64-81 percent of the 2004 revenues and operating income of HEI.

Q. HOW ARE HECO, HELCO AND MECO FINANCED?

A. All of the common stock of HELCO and MECO are owned by HECO. HECO's common stock, in turn, is owned by HEI. The debt, preferred stock, and hybrid securities capital of HELCO and MECO are arranged by HECO, although each subsidiary does have its own debt, preferred stock, and hybrid securities. However, the debt and hybrid securities of HELCO and MECO are guaranteed by HECO and the debt and hybrid securities ratings of each subsidiary are derived from HECO's consolidated financial standing. As a result, HELCO and MECO carry the same debt and hybrid security ratings as HECO. HELCO and MECO have preferred stock ratings one "notch" below HECO since HECO's preferred stock owners have a prior claim on all of HECO's assets to the owners of HELCO's and MECO's preferred stock owners.

Q. ARE THE FINANCING AND COSTS OF CAPITAL OF HELCO, MECO, AND HECO INDEPENDENT OF HEI?

A. No. The debt ratings of HECO (and, thus, HELCO and MECO) are partially tied to the risks and operations of HEI. This has long been recognized by Standard & Poor's (October 11, 1993) CreditWeek) as follows:

> Parent Hawaiian Electric Industries Inc.'s **aggressive diversification activities**--in financial services, freight transportation, and real estate development (representing around 20% of total earnings)—have **intensified consolidated financial risk**. In view of parent debt financing, the **utility** is **not fully insulated** from **higher-risk affiliates**. [Emphasis added.]

Subsequent statements by Standard & Poor's indicate that this concern persisted: (November 1995 Global Sector Review)

> HEI's **diversification**--in financial services, freight transportation, real estate, and passive investments (25% of electric utility and savings bank net income) **intensifies consolidated financial risk**. In view of HEI debt, HECO is **not fully insulated from higher-risk affiliates**. [Emphasis added.]

Standard & Poor's November 4, 1997 CreditWire:

> HEI's ratings largely reflect the credit worthiness of HECO, adjusted for **higher-risk non-utility units**. HECO's ratings reflect an average business profile and gradually improving financials. [Emphasis added.]

Standard & Poor's September 1999 Utility Credit Report

> HEI's aggressive **diversification intensifies consolidated financial risk**. Given parent debt, HECO is **not fully insulated from higher risk non-utility affiliates**. [Emphasis added.]

Even though HEI has, in recent years, divested itself of its more risky non-utility affiliates (e.g., international power), it remains that the utility operations are least risky. This is demonstrated in a more recent (July 9, 2004) Standard & Poor's Rating Direct.

> Rating Methodology
>
> The corporate credit rating of HEI reflects the credit fundamentals of HECO as well as the **higher-risk financial services operations** of American Savings Bank. However, Standard & Poor's does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.
>
> In most circumstances, Standard & Poor's will not rate the debt of a wholly owned subsidiary higher than the rating of the parent. However, exceptions can be made on the basis of structural protections and/or regulatory insulation. In HECO's case, Standard & Poor's believes that there are adequate insulating conditions in Hawaii's statutory and regulatory framework, including orders issued by the Hawaii Public Utilities Commission (PUC) regarding the formation of the HEI's holding company structure, that insulate the utility from the parent's activities. The conditions imposed on HECO, and the PUC's ability, intent, and demonstrated willingness to protect HECO's creditworthiness provide Standard & Poor's with sufficient confidence to separate the corporate credit ratings of HEI and HECO by one notch. [Emphasis added.]

This relationship is further demonstrated by the higher bond ratings which HECO (and HELCO/MECO) maintain relative to HEI. At the current time, HECO's medium term notes are rated Baa1 by Moody's and BBB+ by Standard & Poor's, while HEI's medium term notes are rated lower at Baa2 by

Moody's and BBB by Standard & Poor's (see CA-403). To my knowledge no changes in HECO's bond ratings have occurred since this information request was prepared by HECO.

Q. WHAT ARE THE CURRENT SECURITY RATINGS OF HECO?

A. As shown in CA-403, page 2, the current ratings of HECO are:

	Moody's	S&P
First Mortgage Bonds[7]	A3	A-
Revenue Bonds	Baa1	BBB+
Preferred Stock	Baa2	BBB-
Commercial Paper	P-2	A-2

As this indicates, HECO's most senior securities (i.e., revenue bonds), presently carry "high" triple B ratings by the two major rating agencies.

Q. WHAT HAS BEEN THE TREND IN HECO'S DEBT RATINGS?

A. As CA-403, page 2 indicates, prior to 1990 HECO's most prominent debt (i.e., revenue bonds) was rated A by each of the rating agencies. Moody's reduced HECO ratings in 1989, 1990, and 1991, while S&P also reduced the ratings in 1990. The ratings have remained the same since 1991.

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[7] HECO redeemed all of its first mortgage bonds in 1999. These are the ratings at that time.

Q. WHERE DOES HECO RANK WITHIN THE 'BUSINESS POSITION' CATEGORIES THAT THE RATING AGENCIES HAVE ESTABLISHED?

A. In 1993, Standard & Poor's established a "matrix approach" to its financial benchmarks, which is used, in part, to establish bond ratings. In connection with this matrix approach, Standard & Poor's placed electric utilities within seven "business positions" that are designed to recognize the qualitative business or operating characteristics of the individual utilities. These seven business positions range from above average to below average. HECO was initially listed in the low average category, which placed it in the slightly above average business risk category. Subsequently, HECO was listed as an average business position.[8] Standard & Poor's has subsequently developed a "business profile" system, ranging from "1" (strong) to "10" (weak). HECO has a business profile of "6."[9] Since this business profile is in the middle of the range, it follows that the perceived business risk of companies in this category, including HECO, are average.

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[8] See response to CA-IR-102.

[9] Id.

Q. HOW IS THE REGULATORY CLIMATE IN HAWAII VIEWED?

A. Hawaii's regulatory climate is "Above Average," according to Value Line.[10] It is noteworthy that only 8 of 50 states have "above Average" Regulatory Climate designations.

It is also apparent that the regulatory process in Hawaii serves to minimize the risk of rate base disallowances. This is the case since the Commission's procedures provide for **four opportunities** to review major construction projects prior to their appearance in a rate proceeding. First, the Company annually submits a 5-year capital budget, which generally identifies generation and transmission projects due to the costs of these projects. Second, a 3-year financing plan is submitted when the Company seeks Commission approval to issue securities. Third, the resource planning process and related IRP hearings evaluate both planned construction and DSM programs on a five-year cycle with annual updates to the latest approved plan. Fourth, the Commission's G.O. #7 Standards provide for a submission of capital improvements application seeking Commission approval to commit or expend fund for any single project over $2,500,000.[11] Commission

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10 See Value Line Investment Survey of August 13, 2004, page 1773.

11 In Decision and Order No. 21002 filed on May 27, 2004 in Docket No. 03-0257, the Commission granted, among other things, a request by the electric utilities to increase the $500,000 threshold for seeking Commission approval to commit funds for capital improvement projects to $2,500,000.

approval (or failure to act within 90 days of filing)[12] implies that the project will likely be included in rate base. From a practical standpoint, following Commission review at these steps the likelihood of rate base disapproval is significantly reduced. Thus, the Company's business risk is also reduced. In addition, allowing HECO to continue recovering the fuel costs associated with the change in the price of fuel through the Energy Cost Adjustment Clause also reduces the risk of the Company.

VI. <u>CAPITAL STRUCTURE AND COSTS OF DEBT, HYBRID SECURITIES AND PREFERRED STOCK</u>.

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULTORY FRAMEWORK?

A. A utility's capital structure is important since the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain the capital costs of the company. The rate base – rate of return concept recognizes the assets which are employed in providing utility services and provides for a return on

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[12] Such action may result in the suspension of the application to allow the Commission and/or parties to the proceeding additional time to review the merits of the utility's proposal.

these assets by identifying the liabilities and common equity (and their cost rates) which are used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived form the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar value of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item that normally receives the most attention. This is the case since common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTUE OF HECO?

A. I first examined the five-year historic (2000-2004) capital structure ratios for HECO and HEI. These ratios are shown on CA-404. Pages 1, 2 and 3 of CA-404 show the calculations respectively, for HECO and HEI.

I have summarized below the common equity ratios for each of these entities:

	Including S-T Debt			Excluding S-T Debt		
	HECO	Oahu*	HEI	HECO	Oahu*	HEI
2000	50.3%	46.7%	37.0%	50.7%	51.1%	38.8%
2001	50.3%	50.3%	40.2%	51.7%	52.4%	40.2%
2002	52.2%	51.9%	43.8%	52.4%	52.6%	43.8%
2003	52.9%	52.0%	45.6%	53.1%	53.0%	45.6%
2004	53.7%	53.8%	48.7%	56.4%	56.7%	52.2%

*HECO (Oahu)

This indicates that HECO, on both a consolidated and Oahu only basis, has increased its common equity ratios over the past five years. HEI has also increased its equity ratio over the past five years; on the other hand, it has had generally lower equity ratios than of HECO. It remains that the common equity ratios of HEI are less than those of HECO. This latter comparison does not properly relate to the higher risk nature of the non-HECO subsidiaries of HEI, since the consolidated enterprise should properly have a higher equity ratio than the less risky electric energy operations. This follows since, on a stand-alone basis, subsidiaries with higher levels of business risk would be expected to have higher levels of common equity in order to reduce their financial risk so as to minimize their overall risk.

Q. IS THERE ANYTHING UNIQUE ABOUT HECO'S CAPITAL STRUCTURE?

A. Yes. A significant portion of HECO's debt is revenue bonds, which are issued in conjunction with the Department of Budget and Finance of the State of

Hawaii. This is a source of funding not generally available to many other utilities and represents a favorable circumstance for HECO.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS HECO REQUESTED IN THIS PROCEEDING?

A. Per HECO-2101, as updated, the Company requests use of the following capital structure:

Capital Item	Percent
Short-term Debt	3.22%
Lease Obligation	0.87%
Long-term Debt	36.49%
Hybrid Securities	2.35%
Preferred Stock	1.76%
Common Equity	55.30%

According to Company witness Richard A. Von Gnechten, this capital structure was derived by taking the 2003 capital structure of the Company and adjusting it for expected changes in 2004 and 2005.[13] Mr. Von Gnechten states that this capital structure has been derived using the same methodology employed by HELCO, MECO and HECO in their recent rate proceedings.[14]

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13 See HECO T-21, page 30.

14 See HECO T-21, page 5.

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDERS IN THE MOST RECENT HECO RATE PROCEEDINGS?

A. Yes, I have. The most three recent HECO dockets incorporated the following capital structure ratios:

Capital Structure Item	Docket No. 6531	Docket No. 7700	Docket No. 7766
Short-term Debt	2.45%	5.56%	5.46%
Long-term Debt	41.90%	38.69%	38.76%
Preferred Stock	11.13%	7.32%	6.98%
Common Equity	44.52%	48.44%	48.81%

The proposed ratios for the instant proceeding contain more common equity, in comparison to those requested in the prior proceedings. This reflects a decline in HECO's financial risk.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I will also employ the Company's projected 2005 capital structure. However, I do not include the "Lease Obligation" component of the capital structure, as proposed by HECO. Mr. Carver (CA-T-2) will address this issue and offer an alternative ratemaking treatment for this lease. Furthermore, I note that if HECO proposes to update its capital structure later in the proceeding, I may have further comments at that time.

Q. WHAT ARE THE COSTS OF FIXED-COST CAPITAL IN THE COMPANY'S APPLICATION?

A. The Company's Application (see HECO-2101 as updated) contains the following cost rates:

Capital Structure Item	Cost Rate
Short-term Debt	3.50%
Long-term Debt	6.25%
Hybrid Securities	7.55%
Preferred Stock	5.54%

It appears from the Application that these rates are calculated using the same methodology as in prior proceedings. As a result, I will also use these cost rates in my analyses.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COSTS OF DEBT AND PREFERRED STOCK?

A. No. The cost rates of debt and preferred stock are largely determined by interest/dividend payments, issue prices, and related expenses. Even though alternative methodologies exist for determining the embedded cost rates, the cost rates for debt and preferred stock are generally agreed to, at least within a relatively small range.

The cost of common equity, on the other hand, is not susceptible to specific measurement, primarily because this cost is an opportunity cost. There are, however, several models, which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and comparable earnings - are developed in the following sections of my testimony.

VII. SELECTION OF COMPARISON GROUPS.

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR HECO?

A. As a wholly-owned subsidiary of HEI, HECO's common stock is not publicly-traded. As a result, it is necessary to analyze groups of comparison or "proxy" companies as a substitute for HECO to determine the Company's cost of common equity. One alternative proxy company is HEI. Using HEI is not sufficient on its own, however, because HEI is diversified into non-utility businesses and its stock price and market-derived cost of equity thus reflects its consolidated operations, not just its utility operations. I also note that the Commission stated in Decision and Order No. 16922 dated April 6, 1999 in Docket No. 97-0346 (In RE MECO), on page 40, that they do not consider HEI an appropriate proxy for MECO and did not consider the HEI results.

Another alternative is to select a group of comparison electric utilities. I have examined two such groups for comparison to HECO. I have selected one group using similar criteria cited by the Commission in several prior HECO decisions. In addition, I have selected a group of companies using criteria, which I frequently employ in electric utility rate proceedings.

Q. HOW HAVE YOU SELECTED THE GROUPS OF COMPARISON COMPANIES?

A. My first group of comparison companies was selected using criteria similar to that cited by the Commission in recent HELCO (Decision and Order No. 18365 dated February 8, 2001 in Docket No. 99-0207) and MECO (Decision and Order No. 16922 dated April 6, 1999 in Docket No. 97-0346) Decisions. As I interpret these Decisions, the Commission has noted that it is appropriate to select comparison companies based upon the following criteria:

1. primarily an electric utility, with electric revenues providing most of total company revenues;
2. publicly-traded common stock on New York Stock Exchange;
3. substantially regulated entity;
4. Value Line safety rating of 1 or 2;
5. first mortgage bonds rated within one rating increment of HECO;
6. if a holding company, have only one subsidiary;
7. common equity ratio in the 35 percent to 50 percent range; and
8. be small (total market value of outstanding common equity within $0.45 billion to $3.0 billion range).[15]

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[15] The Commission initially endorsed $2.0 billion as the top end of the market value of common stock range. In Docket No. 97-0346, I proposed the market value criteria be expanded to $3 billion. In its Decision and Order No. 16922, the Commission accepted my proxy group as "reasonable."

The Commission has also identified, in some cases (e.g., [In RE HELCO] Decision and Order No. 13762 dated February 10, 1995 in Docket No. 7764 on page 53) a criterion of nuclear risk (i.e., no nuclear construction) similar to HECO. The Commission further has noted (e.g., [In RE HECO] Decision and Order No. 14412 dated December 11, 1995 in Docket No. 7766 on page 54) that in future cases these selection criteria may "be applied advisedly."

I have selected a group of eight comparison companies based upon these criteria. Page 1 of CA-405 lists the eight comparison companies and identifies the selection criteria.

In addition to this group, I also selected a group of electric companies using alternative selection criteria that I normally employ in electric utility cases. I have selected a group of eight companies based upon the following criteria:

1. Net utility plant of less than $5 billion;
2. No nuclear generation;
3. Electric revenues of greater than 60 percent of total revenues;
4. Common equity ratio in the 40 percent to 55 percent range;
5. Standard & Poor's stock ranking of B or B+; and
6. Moody's bond rating of A or Baa.

These companies are identified on page 2 of CA-405.

Q. HOW DO THESE PROXY GROUPS COMPARE TO THE GROUPS THAT HECO WITNESS MORIN USES IN HIS COST OF CAPITAL ANALYSES?

A. HECO's cost of capital witness (Dr. Roger A. Morin) has not selected proxy groups based upon any criteria specifically designed to compare to HECO or the previously-cited Commission criteria. Rather, he has used broad industry groups, such as Moody's Electric Utilities, vertically integrated electric utilities, and natural gas utilities. In Section XIII of my testimony, I will discuss the deficiencies with Mr. Morin's proxy group of companies.

VIII. DISCOUNTED CASH FLOW ANALYSIS.

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow (DCF) model is one of the oldest, as well as the most commonly-used model for estimating the cost of common equity for public utilities. This Commission has also placed primary reliance (i.e., 50% weight) upon the results of the DCF methodology in determining a utility's cost of common equity, as is evidenced by Decision and Order No. 18365 dated February 8, 2001 in Docket No. 99-0207 (In RE HELCO) at page 75 and Decision and Order No. 16922 dated April 6, 1999 in Docket No. 97-0346 (In RE MECO) at page 52.

The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. When applied to common stocks, the dividend discount model describes the value of a stock as follows:

$$P = \frac{D_1}{(1+K_{1)}} + \frac{D_2}{(1+K_2)^2} + \ldots + \frac{D_n}{(1+K_n)^n} = \sum_{i=1}^{n} \frac{D_t}{(1+K)^t}$$

where: P = current price
D_1 = dividends paid in period 1, etc.
K_1 = discount rate in period 1, etc.
n = infinity

This relationship can be simplified if dividends are assumed to grow at a constant rate of G. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, the price of a stock is determined as follows:

$$P = \frac{D}{(K-g)}$$

where: P = current price
D = current dividend rate
K = discount rate (cost of capital)
g = constant rate of expected growth

This equation can be solved for K (i.e., the cost of capital) to yield the following formula:

$$K = \frac{D}{P} + g$$

This formula essentially states that the return expectations, or required by investors is comprised of two factors: the yield (current income) and the expected growth (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of electric utility stocks described in the previous section with several indicators of expected growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods, which can be used for calculating the yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate yield component is a quarterly compounding variant, which is expressed as follows:

$$Yield = \frac{D_o(1 + 0.5g)}{P_o}$$

This yield component recognizes the timing of dividend payments and dividend increases.

The P_o in my yield calculation is the average (of high and low) stock price for each company for the most recent three-month period (March – May, 2005). The D_o is the current annualized dividend rate for each company.

Q. HOW HAVE YOU ESTIMATED THE GROWTH COMPONENT OF THE DCF EQUATION?

A. The growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the growth component is to reflect the growth expected by investors which is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. There exists a wide array of techniques for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. the 2000-2004 (5 year average) earning retention, or fundamental growth;
2. a 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. the 2005, 2006, and 2008-2010 projections of earnings retention growth;
4. the 2002-2009 projections of EPS, DPS, and BVPS; and
5. the 5-year projections of EPS growth as reported in First call.

I believe this combination of growth indicators reflects a representative and appropriate set with which to estimate investor expectations of growth for the groups of electric companies.

Q. PLEASE DESCRIBE YOUR DCF CALCULATIONS.

A. CA-406 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield. Pages 2-3 show the growth rate for the groups of comparison electric companies. Page 4 shows the DCF calculations, which are presented on several bases: average, individual growth rates/DCF costs, and range of low/high values. These results can be summarized as follows:

	Mid-Point	Average	Median	Range
Comparison Groups:				
PUC Criteria	7.6%	7.8%	8.2%	6.5 – 8.7%
Parcell Criteria	6.0%	7.0%	6.8%	3.8 – 8.2%
Hawaiian Elec. Ind.	7.0%	7.2%		6.0-7.9%

I wish to emphasize that these results are numeric calculations and should not be interpreted to be my DCF findings prior to analysis and interpretation.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe 8.5 percent represents the current DCF cost of equity for HECO. This is approximated by the upper end of the DCF calculations for the groups examined in the previous analysis. I have focused on the high end of the DCF calculations since current financial conditions (low interest rates and high market-to-book ratios for utilities) have the effect of driving DCF results to low levels by historic standards.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS.

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity
R_f = risk free rate
R_m = return on market
β = beta
R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium method does not.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of electric utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk free rate (R_f). The risk-free rate reflects the level of return, which can be achieved without accepting any risk.

In reality, there is no such thing as a risk free asset. In CAPM applications, the risk-free rate is usually recognized by use of U.S. Treasury securities. This follows since Treasury securities are default-free owing to the government's ability to print money and/or raise taxes to pay its debts.

Two types of Treasury securities are often utilized as the R_f component: (a) short-term U.S. Treasury bills; and (b) long-term U.S. Treasury bonds. I have performed CAPM calculations using the three-month average yield (March-May, 2005) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 4.75 percent.

I am aware of, and concur with, the Commission's preference for using the long-term Treasury bond rates as R_f.[16]

Q. WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. I utilized the most current Value Line betas (as of June 13, 2005) for each company in the groups of comparison companies. These are shown on CA-408 and are seen to be within a range of 0.55 to 1.00 (the beta for the entire market is 1.00).

Q. HOW DID YOU ESTIMATE THE MARKET RETURN COMPONENT?

A. The market return component (R_m) represents the expected return from holding the entire market portfolio. In the CAPM, this term technically reflects the return from holding the weighted combination of all assets (i.e., stocks, bonds, real estate, collectibles, etc.). However, the traditional use of CAPM in utility rate proceedings focuses on R_m as the return on common stocks.

Alternative methods have been prepared with which to estimate R_m. As was the case in the DCF analysis concerning investors' expectations of growth, investors do not universally share the same expectations of the return on the overall market. My analysis of the R_m focuses on various returns for the Standard & Poor's 500 composite group, which is a well-recognized index

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[16] See e.g., In RE HECO, Decision and Order No. 13704 dated December 18, 1994 in Docket No. 7700 on page 71.

of the overall stock market. Two measures of return for the S&P 500 group have been performed.

CA-407 shows the return on equity for the S&P 500 group over the period 1978-2004 (all available years reported by S&P). The average return as equity for the S&P 500 group over the 1978-2004 period is 14.01 percent. Based upon these returns, I conclude that the expected return on equity is about 14 percent for the S&P 500 group.

I have also considered the total return of the S&P 500 group, as tabulated by Ibbotson Associates, on both the arithmetic and geometric means. I have considered the total returns for the entire 1926-2004 period, which are as follows:

Arithmetic	12.4%
Geometric	10.4%

I conclude from this that the expected total return for the S&P 500 group is about 12.4 percent. My conclusion is based exclusively on the arithmetic return. I focus on the arithmetic return since the Commission has expressed a preference for use of the Ibbotson returns as the CAPM R_m.[17]

I combine the results of the return on common equity (14 percent) and total return (12.4 percent) and conclude that 13.2 percent is the expected R_m.

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[17] See, for example [In RE MECO], Decision and Order No. 16134 dated December 31, 1997 in Docket No. 96-0040 at page 28.

Q. PLEASE DESCRIBE THE RESULTS OF YOUR CAPM ANALYSIS.

A. CA-408 shows my CAPM results. The results are as follows:

	Mean	Median
Comparison Groups:		
PUC Criteria	10.9%	10.9%
Parcell Criteria	11.2%	10.9%
Hawaiian Elec. Ind.	9.8%	

Q. HAVE YOU PERFORMED AN ALTERNATIVE SET OF CAPM CALCULATIONS?

A. Yes. I have performed an alternative set of CAPM calculations in order to address the Commission's concern with some of my prior CAPM results,[18] wherein it did not accept my use of individual values of R_m and R_f to calculate the risk premium, but rather expressed a preference for use of the risk premium from Ibbotson & Associates. I have developed such a risk premium by comparing the 1926-2004 total returns for:

Large Company Stocks	12.4%
Long-term Government Bonds	5.8%
Risk Premium	6.6%

[18] See, for example, the Commission's Decision and Order No. 16922 in Docket No. 97-0346 [In RE MECO] on page 51.

Page 2 of CA-408 shows my CAPM calculations using this risk premium. The results are:

	Mean	Median
Comparison Groups:		
PUC Criteria	9.4%	9.7%
Parcell Criteria	9.8%	9.5%
Hawaiian Elec. Ind.	8.7%	

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY FOR THE GROUPS OF COMPARISON COMPANIES?

A. The CAPM results collectively indicate costs of 9.4 percent to 9.8 percent for the two groups of comparison companies. In making this determination, I have placed reliance on the long-term Treasury bond yield as the risk free rate and on the use of risk premiums.

X. COMPARABLE EARNINGS ANALYSIS.

Q. PLEASE DESCRIBE THE BASIS OF THE COMPARABLE EARNINGS METHODOLOGY.

A. The comparable earnings method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is based upon the economic concept of opportunity cost. As previously noted the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. If, in the opinion of those who save and commit capital, the prospective return from a given investment is not equal to that available from other investments of similar risk, the available capital will tend to be shifted to the alternative investments. Through this mechanism, opportunity-cost driven pricing signals direct capital to its most productive uses; thus, a free enterprise system promotes an efficient allocation of scarce resources.

The comparable earnings method is designed to measure the returns that are expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The comparable earnings method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return, which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE COMPARABLE EARNINGS METHODOLOGY IN YOUR ANALYSIS OF HECO'S COMMON EQUITY COST?

A. I conducted the comparable earnings methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the comparable earnings analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not strictly backward looking.

Q. ARE YOU AWARE THAT THE COMMISSION HAS NOT ACCEPTED THE RESULTS OF THE COMPARABLE EARNINGS ANALYSES IN RECENT DECISIONS INVOLVING UTILITIES?

A. Yes, I am. The Commission has stated (see, for example, [In RE MECO], Decision and Order No. 16134, dated December 23, 1997 in Docket No. 96-0040 at page 19) that it has not accepted the comparable earnings test as an appropriate technique to estimate the cost of common equity. I continue to believe, however, that the comparable earnings test can be a viable methodology, if applied correctly. As a result, my testimony again contains this methodology. I note, further, that my comparable earnings results are similar to those of my CAPM test, such that they corroborate my CAPM conclusions.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR COMPARABLE EARNINGS ANALYSIS?

A. My comparable earnings analysis considers the experienced equity returns of HEI and the comparison groups of electric utilities for the period 1992-2004 (i.e., the last 13 years). The comparable earnings analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence by unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2000-2004 (the last five years) and 1992-2001 (the most recent period complete business cycle).

I am aware that the Commission has criticized a prior HECO witness (Charles A. Benore) for basing his historical risk premium on a single business cycle (see e.g., [In RE HECO], Decision and Order No. 13704 dated December 28, 1994 in Docket No. 7700 at pages 90-91) since one business cycle is not a sufficient length of time to develop a risk premium. I do not regard this criticism to apply to a comparable earnings analysis.

Q. PLEASE DESCRIBE YOUR COMPARABLE EARNINGS ANALYSIS.

A. CA-409 and CA-410 contain summaries of experienced returns on equity for several groups of companies, while CA-411 presents a risk comparison of utilities versus unregulated firms.

CA-409 shows the earned returns on average common equity and market-to-book ratios for HEI and the two groups of electric utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
PUC Criteria	11.5%	150-155%	10.1-10.5
Parcell Criteria	10.1-11.4%	155-160%	9.3-9.7%
Hawaiian Elec. Ind.	11.0-11.1%	147-151%	10.0-10.5%

These results indicate that historic returns of 10.1-11.5 percent have been adequate to produce market-to-book ratios of 150-160 percent.

Furthermore, projected returns on equity for 2005, 2006 and 2008-2010 are within a range of 9.3 percent to 10.5 percent for the electric utility groups. These relate to 2004 market-to-book ratios of 150 percent and higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED MARKETS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 group, since this is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. CA-410 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past thirteen years (<u>i.e.</u>, 1992-2004). As this exhibit indicates, over the two periods this group's average earned returns ranged from 12.2-14.7 percent with market-to-book ratios ranging between 334-341 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR HECO?

A. The recent earnings of the electric utility and S&P 500 groups can be utilized as an indication of the level of return realized, and expected in the regulated and competitive sectors of the economy. In order to apply these returns to

HECO, however, it is necessary to compare the risk levels of this utility and the electric industry with those of the competitive sector. I have done this in CA-411, which compares several risk indicators for the S&P 500 group, the electric utility groups, and HEI.

The information in this schedule indicates that the S&P 500 group is more risky than the electric utility comparison groups. HEI (on a consolidated basis) is also perceived to have similar risk to that of the comparison groups and less risk than the S&P 500 group.

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE COMPARABLE EARNINGS ANALYSIS?

A. Based on the recent earnings and market-to-book ratios, I believe the comparable earnings analysis indicates that the cost of equity for electric utilities and HECO is no more than 10 percent. Recent returns of 10.1-11.5 percent have resulted in market-to-book ratios of 150 or greater. Prospective returns of 9.3-10.5 percent have also been accompanied by market-to-book ratios of over 150 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent.

XI. RETURN ON EQUITY RECOMMENDATION.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies collectively indicate a cost of equity in the range of 8½ percent to 10 percent for the electric utility industry, as summarized below:

Discounted Cash Flow	8½%
Capital Asset Pricing Model	9.4-9.8%
Comparable Earnings	10%

My overall conclusion from these results is a range of 8½ percent to 10 percent, which focuses on the upper ends of my findings.

Q. WHAT RETURN ON EQUITY DO YOU RECOMMEND FOR HECO?

A. My analyses have indicated a cost of equity for similar-risk electric utilities of 8½ percent to 10 percent. I have considered several factors in reaching a conclusion as to how HECO's cost of equity should be derived from this range.

First, my analysis of risk has indicated that HECO has similar business risk in comparison to electric utilities in general. HEI, on a consolidated basis, is perceived to have similar risk to electric utilities in general. A part of this perception is a result of HEI's non-regulated operations, which represents a risk which ratepayers should not bear in the form of a higher cost of equity. On balance, HECO has total compensable business risk which is similar to the electric utility industry.

Second, HECO's common equity ratio has increased since the last proceeding involving the Company and its subsidiaries. This reflects a decline in the Company's financial risk.

Third, the regulatory climate in Hawaii is "above average." As I noted previously, only eight of fifty states have an "Above Average" Regulatory Climate according to Value Line. This indicates that HECO is subject to supportive regulatory treatment, which reduces its regulatory risk.

Fourth, in developing the 8½-10 percent range, I have focused on the upper ends of the findings of each model (e.g., highest growth rates in DCF, use of long-term Treasury bonds in CAPM, focus on upper end of each model result).

Based upon these factors, it is my belief that the fair cost of common equity for HECO is similar to that of the groups of electric utilities, which I have examined. This conclusion is not surprising since both of the two comparison groups were chosen based upon criteria designed to produce similar risk companies to HECO.

Q. IN RECENT HECO, HELCO AND MECO PROCEEDINGS, THE COMMISSION HAS MADE AN UPWARD ADJUSTMENT OF UP TO 115 BASIS POINTS ABOVE THE COST OF EQUITY FOR COMPARISON ELECTRIC UTILITIES. DO YOU HAVE ANY COMMENTS ON THIS?

A. Yes, I do. The Commission has, in some recent cases (Docket No. 99-0207 for HELCO and Docket No. 97-0346 for MECO) added an adjustment of 50 basis points to the cost of equity for comparison companies. The Commission's decisions in these proceedings cited higher business risk (higher operating ratio, lower quality of earnings, and weak level of internally generated funds for construction), current national and local economic conditions, and HECO's minimal investment grade bond rating as matters of concern.

HECO has requested a 40 basis point adjustment in this proceeding, based upon Dr. Morin's conclusions that HECO is more risky than his comparison groups.

Q. DO YOU AGREE THAT THIS TYPE OF ADJUSTMENT IS WARRANTED?

A. No. I do not believe that current circumstances warrant an upward adjustment to the cost of equity for the comparison groups.

It is important to review the history of HECO's cost of equity adjustments. To the best of my knowledge, based upon a review of

Commission decisions, the relevant Commission decisions dealing with this issue were:

Company	Docket No.	Date	Adjustment
MECO	7000	Aug. 5, 1994	115 basis points
HECO	7700	Dec. 28, 1994	115 basis points
HELCO	7764	Feb. 10, 1995	110 basis points
HECO	7766	Dec. 11, 1995	90 basis points
HELCO	94-0140	Apr. 2, 1997	50 basis points
MECO	97-0346	Apr. 6, 1999	50 basis points
HELCO	99-0207	Feb. 8, 2001	50 basis points

As this indicates, the impetus for the adjustments occurred during the 1993-1994 period, as reflected in Commission orders in 1994-1995. Not coincidentally, this was also the time period during which HECO, MECO and HELCO were experiencing downgrades of their securities. I am also aware that, during this time period, the Commission's final rate case decisions were awarded at a slower pace.

In summary, the circumstances that HECO presently encounters, both from the regulatory and financial standpoints, are much improved in comparison to the situation in the 1990s when the Commission first made an upward adjustment to HECO's cost of equity. As stated elsewhere in my testimony, HECO's financial status has improved, along with a reduction in its construction program. The Commission's response time for rate cases has improved and, in fact, the Hawaii Commission is one of a few U.S. commissions to have an "above average" rating by Value Line. I note that even HECO's own perceptions of its relative risks have reflected a decline as its request of 0.40 percent upward adjustment in this case is lower than any previous Commission award.

Q. HOW DO YOU PROPOSE THAT FLOTATION COSTS BE TREATED?

A. I maintain that if a utility has no stated plans for a public offering of common equity during the period in which rates will be in effect, no adjustment for flotation costs is required. If a utility intends to have a public offering of common stock, it is proper that flotation costs only apply to the new stock being issued. Finally, it is important that a utility only recover those costs actually incurred. I note that this position differs from that of HECO, since Dr. Morin proposes an adjustment of 30 basis points (0.30 percent) to HECO's cost of equity to account for his perception of flotation costs.[19]

In the case of HECO, common equity is provided by HEI. This relationship is further complicated by the non-utility operations of HEI and the previous analysis the lower common equity ratios of these subsidiaries.

It is my recommendation that the Commission only permit HECO to recover issuance costs, which are demonstrated by the Company to be incurred as a result of equity issues that are properly attributable to HECO.

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[19] See HECO T-20, page 47.

XII. TOTAL COST OF CAPITAL.

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR HECO?

A. CA-412 reflects the total cost of capital for the Company using the 2005 capital structure, the Company's proposed costs of debt, hybrid securities and preferred stock, and my cost of common equity recommendation. The resulting total cost of capital is a range of 7.43-8.27 percent (7.85 percent mid-point). I recommend the 7.85 percent mid-point be used to establish HECO's fair rate of return.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. CA-413 shows the pre-tax coverage that would result if HECO earned the mid-point of my cost of capital recommendation. This calculation reflects the impact of purchased power obligations. As the results indicate, the mid-point of my recommended range would produce a coverage level, which is within the benchmark range for a BBB rated utility. (See CA-413). In addition, the total debt ratio (including purchased power) in my recommendation is 50.52 percent. This is also in the "BBB" benchmark range.

In reaching these conclusions, I note HECO's "average" business position and "6" business profile.

XIII. COMMENTS ON COMPANY TESTIMONY.

Q. HAVE YOU REVIEWED THE TESTIMONY OF HECO WITNESS ROGER MORIN?

A. Yes, I have.

Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S COST OF EQUITY RECOMMENDATION FOR HECO?

A. Dr. Morin is recommending an 11.5 percent cost of common equity for HECO. This recommendation is based upon his implementation of the following cost of equity models:

	Morin Conclusions
CAPM	
Traditional	11.7-12.2%
Empirical	12.1-12.6%
Risk Premium	
Historical Electric	11.4-11.9%
Historical Natural Gas	11.5-12.0%
Allowed R.P. Electric	11.2-11.3%
DCF	
Moody's Electrics Zacks	9.6%
Moody's Electrics Value Line	9.5%
Vertically Integrated Electrics Zacks	9.9%
Vertically Integrated Electrics Value Line	10.6%
Natural Gas Distribution Zacks	9.7%
Natural Gas Distribution Value Line	10.5%

Based upon these results, he concludes that 11.1 percent is the cost of equity for an "average risk electric utility." He recommends an 11.5 percent return on equity for HECO. His recommendation includes a 0.3 percent increment for flotation costs.

Q. YOU PREVIOUSLY NOTED THAT DR. MORIN'S PROXY GROUPS WERE NOT SELECTED USING CRITERIA CONSISTENT WITH PAST COMMISSION PRECEDENT. WHAT ARE THE IMPLICATIONS OF THIS?

A. Over the past several rate proceedings involving HECO, HELCO, and MECO, the Commission has provided some rather precise definitions of what it considers to be appropriate proxy companies for use in determining the cost of equity for these companies. My testimony, as indicated in a prior section, follows these guidelines. Dr. Morin's analyses, on the other hand, do not. Instead, he simply applies his cost of equity analyses to several broad groups of utilities, not all of which are even electric utilities. None of his proxy groups are selected based upon an analysis of the factors that make these companies similar to HECO. As a result, I believe that Dr. Morin's cost of equity analyses do not properly address HECO's risks and required returns. Use of these broad proxy groups does not provide the required risk profiles and specific recognition of HECO's required returns.

Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S CAPM ANALYSES?

A. Dr. Morin performs CAPM analyses for electric utilities in general. He combines a 0.78 beta with 5.5 percent and 6.0 percent level cost of long-term (30-year) Treasury bonds, and a 7.5 percent risk premium to get the following CAPM results:

$$K = RF + \beta(RP) = 5.5\% + .78(7.5\%) = 11.4\%$$

$$K = RF + \beta(RP) = 6.0\% + .78(7.5\%) = 11.9\%$$

He then adds a 0.3 percent flotation costs adjustment to this to get a 11.7 percent to 12.2 percent CAPM result.

Q. DO YOU AGREE WITH THIS CAPM ANALYSIS?

A. No, I do not.

Q. WHICH COMPONENTS OF HIS CAPM ANALYSIS DO YOU DISAGREE WITH?

A. I disagree with the risk-free rate and risk premium components.

Q. WHY DO YOU DISAGREE WITH THE RISK FREE RATE?

A. Dr. Morin uses a range of values for his risk-free rate of 5.5 percent to 6.0 percent. He describes his risk-free rate as "the level of U.S. Treasury 30-year long-bond yields prevailing in May 2004."[20] The U.S. Treasury no longer sells 30-year Treasury bonds and has not done so for several years. The longest maturity of Treasury bonds reported by the Federal Reserve (e.g., in the Federal Reserve Statistical Release H.15 (519)) is 20 years. In addition, the 20-year Treasury bond is used by Ibbotson Associates studies as the standard for long-term government bonds. It is therefore inconsistent to

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[20] See HECO T-20, page 22.

use a thirty-year bond in conjunction with a risk premium developed using twenty-year bonds.

As I indicated previously, the latest three-month average of 20-year Treasury bonds is 4.73 percent. The latest month's yield (i.e., May, 2005) is 4.56 percent. I believe that 4.73 more properly reflects the risk-free rate.

Q. WHAT IS YOUR DISAGREEMENT WITH DR. MORIN'S MARKET RISK PREMIUM COMPONENT?

A. Dr. Morin's 7.5 percent risk premium is derived from two studies: (a) the 1926-2003 Ibbotson Associates study showing a 7.2 percent differential between common stocks and the "income component" of Treasury bonds; and (b) a DCF analysis he performed for Value Line's aggregate stock market index and growth forecasts versus long-term Treasury bonds produced a 7.8 percent differential.

I disagree with the first study since Dr. Morin improperly used "income returns" from the Ibbotson Associates study, rather than "total returns." Dr. Morin compared the differential between total returns for common stocks (i.e., dividends and capital gains) and income returns for Treasury bonds. As such, he has ignored the capital gains component of the Treasury bonds return. As I indicated in my earlier testimony, the differential between total returns of common stocks and Treasury bonds is 6.6 percent (a figure Dr. Morin acknowledges on page 24 of HECO T-20).

Dr. Morin's second study relies upon his conclusion that the "expected return on the aggregate equity market" is 13.3 percent, which he derives by performing DCF analyses for Value Line aggregate market. He combines a 0.3 percent dividend yield with projected growth rates of DPS (9.0 percent) and EPS (15.9 percent) to arrive at a mid-point 12.8 percent return. He then adjusted the dividend yield by the growth rate to arrive at his 13.1 percent DCF cost, which he in turn compared to the 5.5 percent 30-year Treasury bond yields to arrive at a 7.8 percent risk premium.

I do not believe this is an appropriate method by which to estimate the risk premium. Dr. Morin has not attempted to verify that the Value Line group of some 5,000 stocks is an appropriate standard for the risk premium (which is normally performed by using a smaller sample of large companies, such as the S&P 500).

Q. PLEASE DESCRIBE DR. MORIN'S "EMPIRICAL" CAPM ANALYSIS.

A. Dr. Morin also employs what he describes as an "empirical" CAPM analysis. In this, he assumes that the appropriate beta in a CAPM analysis is a combination of the actual industry beta with a 75 percent weight and a beta of 1 with a 25 percent weight. This form of the CAPM thus assumes that beta for an industry understates the industry's volatility and thus risk and it is necessary to substitute the overall market's beta (i.e., 1.0) for one-fourth of the industry's actual beta.

The use of an empirical CAPM overstates the cost of equity for companies with betas below that of the market. What the empirical CAPM actually does is inflate the CAPM cost for the selected company or industry on one-fourth of its equity and assumes that one-fourth of the company has the risk of the overall market. This is not appropriate for HECO or for other utilities.

I note that Dr. Morin's "empirical" CAPM is similar to a "zero beta" CAPM proposed by MECO witness Paul R. Moul in a 1999 proceeding before this Commission. In its decision in that proceeding (Docket No. 97-0346, In Re (MECO)), the Commission did not accept MECO's proposed CAPM.[21]

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF DR. MORIN'S RISK PREMIUM ANALYSIS.

A. Dr. Morin performs three risk premium analyses. Each of these involved the estimation of an equity risk premium over the 5.5 percent and 6.0 percent long-term Treasury bond yields used as the risk-free rate in his CAPM analyses. The three risk premiums he developed are:

Historic risk premium for electric industry,

Historic risk premium for gas distribution industry, and

Allowed risk premiums for electric industry.

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[21] See Decision and Order No. 16922, in Docket No. 97-0346, page 50.

Q. PLEASE DESCRIBE DR. MORIN'S HISTORIC RISK PREMIUM FOR THE ELECTRIC INDUSTRY.

A. Dr. Morin's historic risk premium for the electric industry involves an examination of the total returns of 20-year Treasury bonds (capital gains/losses plus interest) and Moody's Electric Utility Stock Index (capital gains/losses plus dividend yield) over the period 1931-2001. The average historical difference between the electric utility returns and the Treasury bond returns was 5.6. His historic risk premium for the electric industry simply added the 5.5 percent and 6.0 percent current Treasury bond yield to the 5.6 percent historic risk premium to get 11.1 percent and 11.6 percent results. To this he added 0.3 percent for flotation cost.

Q. DO YOU AGREE WITH THIS METHODOLOGY FOR ESTIMATING THE COST OF EQUITY FOR HECO?

A. No, I do not. Dr. Morin's historic risk premium of 5.6 percent is simply an examination of historical events going back to 1931. He has made no demonstration that economic and financial conditions in 2005 are similar to those in 1931 (Great Depression), 1942 (World War II), 1974 (Arab Oil Embargo), or any other year. The use of such a methodology implicitly assumes that the events of each of these years can have the same influences at the current time.

In addition, the risk premiums developed by Dr. Morin are generally dominated by the influence of capital gains in many years. For example, the year 2000 stock return of 71.74 percent reflects a 65.40 percent capital gain component. I do not believe it is proper to assign HECO's cost of equity based upon a methodology, which is dominated by stock market changes and bond market changes.

It is also apparent that the risk premium level has been very volatile over the period 1931-2001. The highest risk premium was 71.96 percent in 1935 and the lowest was -37.34 percent in 1937. The averages by decade have also been quite different, as is shown on my CA-414. This indicates that the decade of the 1950's dominates the risk premium averages with a 14.06 percent premium. The decade of the 1990's, in contrast, showed a 0.02 percent risk premium. Dr. Morin's methodology weights these equally. It is doubtful that investors place equal weight on events in the 1950's and 1990's in making investment decisions, yet Dr. Morin's risk premium analysis implicitly assumes this is the case.

Q. PLEASE DESCRIBE DR. MORIN'S HISTORIC RISK PREMIUM ANALYSIS FOR THE GAS DISTRIBUTION INDUSTRY.

A. Dr. Morin's risk premium analysis for the gas distribution industry parallels his risk premium analysis for the electric utility industry, except that he uses Moody's Natural Gas Distribution Index for the stock component. As such, this analysis is subject to the same criticisms and weaknesses. This method is thus inappropriate for the purposes of estimating HECO's cost of equity.

Q. PLEASE DESCRIBE DR. MORIN'S ANALYSIS OF ALLOWED RISK PREMIUMS FOR THE ELECTRIC UTILITY INDUSTRY.

A. In this phase of his risk premium testimony, Dr. Morin compares the differential between allowed returns on equity for electric utilities and long-term Treasury bonds over the period 1995-2004. The average spread over this period was 5.4 percent, but Dr. Morin does not utilize this differential as his risk premium. Instead, he performs regression analyses to track the risk premium in terms of rising and falling interest rates. He then concludes that a 5.7 percent risk premium is appropriate in conjunction with a 5.5 percent Treasury bond yield and a 5.3 percent risk premium applies to a 6.0 percent treasury bond yield. This adjustment is not consistent with Dr. Morin's historic risk premium analyses where he simply took the average risk premium over the entire 1931-2001 period and applied this to the current level of Treasury bond yields

Q. WHAT IS YOUR UNDERSTANDING OF DR. MORIN'S DCF ANALYSES?

A. Dr. Morin performs several sets of DCF analyses for groups of electric utilities, vertically-integrated electric utilities, and natural gas distribution utilities. In these analyses, he uses "spot" dividend yields for each company as of May,

2004. For the growth rates, he used two indicators of growth - Zacks 5-year EPS growth projections and Value Line projections of EPS growth.

The major problem with Dr. Morin's DCF analyses is the fact that he has used only one indicator of growth – projections of EPS. As I indicated in my DCF analysis, it is customary and proper to use alternative measures of growth.

Dr. Morin's DCF analyses implicitly assume that investors rely exclusively on EPS projections in making investment decisions. This is a very dubious assumption and Dr. Morin has offered no evidence that it is correct. I note, for example, that Value Line – one of the sources of his growth rate estimates – contains many statistics, both of a historic and projected nature, for the benefit of investors who subscribe to this publication and presumably make investment decisions based at least in part from the information contained in Value Line. Yet, Dr. Morin would have us believe that Value Line subscribers and investors focus exclusively on one single number from this publication.

I note, in this regard, that the DCF model is a "cash flow" model. The cash flow to investors in a DCF framework is dividends. Dr. Morin's DCF model, in contrast, does not even consider dividend growth rates.

Q. PLEASE SUMMARIZE YOUR COST OF CAPITAL FINDINGS AND INDICATE HOW YOUR RECOMMENDATIONS DIFFER FROM THE PROPOSALS OF HECO.

A. My cost of capital recommendation is 7.83 percent, which incorporates a return on equity of 9.25 percent. HECO's overall cost of capital request is 9.08 percent and a return on equity of 11.5 percent.

My cost of capital primarily differs from that of HECO because my recommended return on equity of 9.25 percent is below the 11.5 percent request by HECO.

XIV. <u>OTHER CONCERNS</u>.

Q. DO YOU WISH TO COMMENT ON ANY OTHER POTENTIAL COST OF CAPITAL ISSUES THAT MAY ARISE IN THIS PROCEEDING?

A. Yes, I do. I am aware that, in a separate proceeding, HECO appears to be maintaining that certain amendments to its Kalaeloa PPA contract may potentially have the impact of requiring that the financial results of Kalaeloa be consolidated into HECO's capital structure. There has been some concerns raised that such a consolidation may have the potential impact of requiring HECO to retire some of its lower cost debt, thereby raising its cost of debt and ultimately its overall cost of capital.

I do not believe that this potential issue should be made a part of the present proceeding. The need for any potential consolidation, as well as any potential impact on HECO's capital structure and cost of debt is unknown at this time. It would be very speculative to try to predict any potential impacts of a potential consolidation of Kalaeloa.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

CA-T-4
DOCKET NO. 04-0113

EXHIBITS

OF

DAVID C. PARCELL

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

<u>Insurance Economics</u> – Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

<u>Special Studies</u> – Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

<u>Franchise, Merger & Anti-Trust Economics</u> – Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in

mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics – Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses – Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.
The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Other

Editorial Review Board (Industry and Government) for Journal of Managerial Issues, 1992-present.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.8%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.6%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.9%	-0.3%	5.8%	2.4%	1.2%
2003	3.0%	0.0%	6.0%	1.9%	4.0%
2004	4.4%	4.2%	5.5%	3.3%	4.1%
2002					
1st Qtr.	3.4%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.4%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.6%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.7%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.9%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	4.1%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.4%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	4.2%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	4.5%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.3%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.8%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.1%	3.8%	5.3%	4.4%	5.6%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

HAWAIIAN ELECTRIC INDUSTRIES
SEGMENT FINANCIAL INFORMATION
2002-2004
($000)

Segment	Revenue	Operating Income	Capital Expenditures	Total Assets
2002				
Electric Utility	$1,257,176 76%	$194,956 73%	$114,558 89%	$2,493,436 28%
Bank	$399,255 24%	$92,883 35%	$13,117 10%	$6,328,606 71%
Other	-$2,730 0%	-$21,406 -8%	$407 0%	$111,511 1%
HEI Consolidated	$1,653,701	$266,433	$128,082	$8,933,553
2003				
Electric Utility	$1,396,685 78%	$176,565 67%	$146,964 90%	$2,581,256 28%
Bank	$371,320 21%	$92,755 35%	$15,798 10%	$6,515,208 71%
Other	$13,311 1%	-$5,753 -2%	$129 0%	$104,694 1%
HEI Consolidated	$1,781,316	$263,567	$162,891	$9,201,158
2004				
Electric Utility	$1,550,671 81%	$173,903 64%	$201,236 94%	$2,770,985 29%
Bank	$364,284 19%	$104,974 39%	$13,085 6%	$6,766,505 70%
Other	$9,102 0%	-$7,917 -3%	$333 0%	$73,137 1%
HEI Consolidated	$1,924,057	$270,960	$214,654	$9,610,627

Source: Hawaiian Electric Industries, Inc., Form 10-K.

BOND RATINGS

	HECO		MECO		HELCO		HEI	
Date	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
Corporate Credit Rating	Baa1	BBB+						BBB
First Mortgage Bonds	A3	A-						
Revenue Bonds (uninsured)	Baa1	BBB+	Baa1	BBB+	Baa1	BBB+		
Medium Term Notes	Baa1	BBB+	Baa1	BBB+	Baa1	BBB+	Baa2	BBB

Note: HECO, MECO, and HELCO no longer have any first mortgage bonds, medium term notes, or uninsured revenue bonds outstanding.

Source: Response to CA-IR-104.

HISTORY OF SECURITY RATINGS
HAWAIIAN ELECTRIC COMPANY

	First Mortgage Bonds		Revenue Bonds		Preferred Stock		Commercial Paper	
Year	Moody's	S&P	Moody's	S&P	Moody's	S&P	Moody's	S&P
1974	A	A	A		a	A	P-1	
1975	A	A	A		a	A	P-1	
1976	A	A	A		a	A	P-1	
1977	A	A	A		a	A	P-1	A-1
1978	A	A	A		a	A	P-1	A-1
1979	A	A	A		a	A	P-1	A-1
1980	A	A	A		a	A	P-1	A-1
1981	A	A	A		a	A	P-1	A-1
1982	A1	A+	A2	A	a1	A+	P-1	A-1
1983	A1	A+	A2	A	a1	A+	P-1	A-1
1984	A1	A+	A2	A	a1	A+	P-1	A-1+
1985	A1	A+	A2	A	a1	A+	P-1	A-1+
1986	Aa3	A+	A1	A	aa3	A+	P-1	A-1+
1987	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1988	Aa3	A	A1	A-	aa3	A-	P-1	A-1
1989	A1	A	A2	A-	a1	A-	P-1	A-1
1990	A2	A-	A3	BBB+	a2	BBB+	P-1	A-2
1991	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1992	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1993	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1994	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1995	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1996	A3	BBB+	Baa1	BBB+	baa1	BBB+	P-2	A-2
1997	A3	A-	Baa1	BBB+	baa1	BBB+	P-2	A-2
1998	A3	A-	Baa1	BBB+	baa1	BBB-	P-2	A-2
1999	All first mortgage bonds		Baa1	BBB+	baa1	BBB-	P-2	A-2
2000	redeemed in 1999.		Baa1	BBB+	baa1	BBB-	P-2	A-2
2001			Baa1	BBB+	baa2	BBB-	P-2	A-2
2002			Baa1	BBB+	baa2	BBB-	P-2	A-2
2003			Baa1	BBB+	baa2	BBB-	P-2	A-2
2004			Baa1	BBB+	baa2	BBB-	P-2	A-2

HAWAIIAN ELECTRIC COMPANY (CONSOLIDATED)
CAPITAL STRUCTURE RATIOS
2000 - 2004
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2000	$825,012	$134,293	$667,731	$13,162
	50.3%	8.2%	40.7%	0.8%
	50.7%	8.3%	41.0%	
2001	$877,154	$134,293	$685,269	$48,297
	50.3%	7.7%	39.3%	2.8%
	51.7%	7.9%	40.4%	
2002	$923,256	$134,293	$705,270	$5,600
	52.2%	7.6%	39.9%	0.3%
	52.4%	7.6%	40.0%	
2003	$944,443	$134,293	$699,420	$6,000
	52.9%	7.5%	39.2%	0.3%
	53.1%	7.6%	39.3%	
2004	$1,017,104	$34,293	$752,735	$88,568
	53.7%	1.8%	39.8%	4.7%
	56.4%	1.9%	41.7%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-493.

HAWAIIAN ELECTRIC COMPANY (OAHU ONLY)
CAPITAL STRUCTURE RATIOS
2000 - 2004
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2000	$494,295	$82,293	$390,218	$91,362
	46.7%	7.8%	36.9%	8.6%
	51.1%	8.5%	40.4%	
2001	$539,060	$82,293	$407,676	$42,697
	50.3%	7.7%	38.0%	4.0%
	52.4%	8.0%	39.6%	
2002	$570,480	$82,293	$432,597	$13,700
	51.9%	7.5%	39.4%	1.2%
	52.6%	7.6%	39.9%	
2003	$582,562	$82,293	$434,824	$20,700
	52.0%	7.3%	38.8%	1.8%
	53.0%	7.5%	39.5%	
2004	$640,892	$52,293	$436,503	$61,460
	53.8%	4.4%	36.6%	5.2%
	56.7%	4.6%	38.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to CA-IR-101 and CA-IR-492.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
CAPITAL STRUCTURE RATIOS
2000 - 2004
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2000	$839,059	$234,406	$1,088,731	$104,398
	37.0%	10.3%	48.0%	4.6%
	38.8%	10.8%	50.4%	
2001	$929,665	$234,406	$1,145,769	$0
	40.2%	10.1%	49.6%	0.0%
	40.2%	10.1%	49.6%	
2002	$1,046,300	$234,406	$1,106,270	
	43.8%	9.8%	46.3%	0.0%
	43.8%	9.8%	46.3%	
2003	$1,089,031	$234,406	$1,064,420	$0
	45.6%	9.8%	44.6%	0.0%
	45.6%	9.8%	44.6%	
2004	$1,210,945	$34,405	$1,166,735	$76,611
	48.7%	1.4%	46.9%	3.1%
	50.2%	1.4%	48.4%	

Note: Percentages may not total 100.0% due to rounding.

Source: Hawaiian Electric Industries, Inc. Form 10-K.

COMPARISON COMPANIES
BASIS FOR SELECTION
USING COMMISSION CRITERIA

Company	Market Value of Common Stock ($000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety Ranking	Moody's/ Bond Rating	S&P Business Profile
Hawaiian Electric Industries	$2,400,000	78%	52%	2	Baa1*	6
Comparison Group*						
CH Energy Group	$725,000	56%	59%	1	A2	3
Great Plains Energy	$2,200,000	51%	53%	2	A2	7
NSTAR	$2,900,000	83%	40%	1	A1	1
Otter Tail Power	$725,000	44%	61%	2	A2	8
Pinnacle West Capital	$3,800,000	66%	50%	1	Baa1	6
PNM Resources	$1,500,000	75%	53%	2	Baa2	6
SCANA	$4,300,000	43%	43%	2	A1	4
Wisconsin Energy	$4,000,000	49%	43%	2	A1	4

* Selected using following criteria:
Market Value of Common Stock of
Electric Revenues of 40% or greater.
Common Equity Ratio of 40% or greater.
Value Line Safety Ranking of 1 or 2.
Moody's bond ratings of Baa or A.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
BASIS FOR SELECTION
USING PARCELL CRITERIA

Company	Net Utility Plant ($000)	Percent Revenues Electric	Common Equity Ratio	Standard & Poor's Stock Ranking	Moody's/ Bond Rating	S&P Business Profile
Hawaiian Electric Industries	$2,400,000	78%	52%	B+	Baa1*	6
Comparison Group*						
Avista	$1,976,200	89%	41%	B	Baa3	6
Cleco	$1,060,100	76%	53%	B+	A3	6
Empire District Electric	$857,000	93%	49%	B	Baa1	6
IDACORP	$2,200,000	92%	51%	B	A3	5
NSTAR	$3,580,000	83%	40%	B+	A1	1
Puget Energy	$4,135,000	62%	43%	B	Baa2	4
UIL Holdings	$560,000	63%	50%	B+	Baa2	
Vectren	$2,130,000	69%	51%	B+	A3	4

* Selected using following criteria:
Net Utility Plant of $5 billion or less
No nuclear generation.
Electric Revenues of 60% or greater.
Common Equity Ratio of 40% or greater.
Standard & Poor's Stock Ranking of B, B+, or A-.
Moody's bond ratings of Baa or A.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	March - May, 2005 HIGH	LOW	AVERAGE	YIELD
Comparison Group - PUC Criteria					
CH Energy Group	$2.16	$47.25	$42.53	$44.89	4.8%
Great Plains Energy	$1.66	$32.30	$29.40	$30.85	5.4%
NSTAR	$2.32	$58.95	$53.35	$56.15	4.1%
Otter Tail	$1.12	$25.46	$24.02	$24.74	4.5%
Pinnacle West Capital	$1.90	$44.34	$41.29	$42.82	4.4%
PNM Resources	$0.74	$29.39	$26.05	$27.72	2.7%
SCANA	$1.56	$42.29	$36.56	$39.43	4.0%
Wisconsin Energy	$0.88	$36.42	$34.01	$35.22	2.5%
Average					**4.1%**
Comparison Group - Parcell Criteria					
Avista	$0.54	$18.37	$16.31	$17.34	3.1%
Cleco	$0.90	$22.00	$19.75	$20.88	4.3%
Empire District Electric	$1.28	$23.93	$21.82	$22.88	5.6%
IDACORP	$1.20	$29.50	$26.22	$27.86	4.3%
NSTAR	$2.32	$58.95	$53.35	$56.15	4.1%
Puget Energy	$1.00	$23.48	$20.73	$22.11	4.5%
UIL Holdings	$2.88	$53.25	$49.23	$51.24	5.6%
Vectren	$1.18	$27.92	$26.01	$26.97	4.4%
Average					**4.5%**
Hawaiian Electric Industries	$1.24	$27.40	$24.60	$26.00	**4.8%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2000	2001	2002	2003	2004	Average	2005	2006	'08-'10	Average
Comparison Group - PUC Criteria										
CH Energy Group	3.1%	3.1%	0.0%	2.0%	1.7%	2.0%	1.5%	1.5%	2.5%	1.8%
Great Plains Energy	2.6%	0.0%	2.3%	4.4%	5.1%	2.9%	3.0%	3.0%	3.5%	3.2%
NSTAR	4.8%	5.0%	5.2%	5.2%	4.9%	5.0%	4.5%	4.5%	4.5%	4.5%
Otter Tail	5.4%	5.8%	6.0%	3.2%	2.5%	4.6%	3.5%	3.5%	4.0%	3.7%
Pinnacle West Capital	6.8%	7.3%	2.9%	2.6%	2.3%	4.4%	3.0%	3.0%	2.0%	2.7%
PNM Resources	6.5%	12.3%	3.1%	3.0%	4.5%	5.9%	4.0%	4.0%	3.0%	3.7%
SCANA	4.8%	4.6%	5.5%	5.5%	5.6%	5.2%	5.5%	5.5%	4.5%	5.2%
Wisconsin Energy	0.0%	6.0%	8.3%	7.4%	4.9%	5.3%	6.5%	6.5%	6.0%	6.3%
Average	4.3%	5.5%	4.2%	4.2%	3.9%	**4.4%**	3.9%	3.9%	3.8%	**3.9%**
Comparison Group - Parcell Criteria										
Avista	8.0%	4.8%	1.2%	3.4%	1.4%	3.8%	3.0%	4.5%	4.0%	3.8%
Cleco	6.5%	6.5%	5.6%	3.5%	4.0%	5.2%	4.5%	4.5%	4.5%	4.5%
Empire District Electric	0.5%	0.0%	0.0%	0.1%	0.0%	0.1%	0.5%	1.5%	2.5%	1.5%
IDACORP	7.5%	6.3%	0.0%	0.0%	2.7%	3.3%	3.0%	3.0%	3.0%	3.0%
NSTAR	4.8%	5.0%	5.2%	5.2%	4.9%	5.0%	4.5%	4.5%	4.5%	4.5%
Puget Energy	3.6%	0.0%	1.3%	2.1%	2.8%	2.0%	2.5%	3.0%	3.5%	3.0%
UIL Holdings	4.0%	3.8%	0.6%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%	0.0%
Vectren	1.5%	0.3%	4.8%	3.0%	2.0%	2.3%	3.5%	4.0%	3.5%	3.7%
Average	4.6%	3.3%	2.3%	2.2%	2.2%	**2.9%**	2.7%	3.1%	3.2%	**3.0%**
Hawaiian Electric Industries	1.7%	4.4%	4.3%	3.9%	1.1%	**3.1%**	2.0%	2.5%	3.5%	**2.7%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '01-'03 to '08-'10 Growth Rates EPS	DPS	BVPS	Average
Comparison Group - PUC Criteria								
CH Energy Group	-3.0%	0.0%	2.0%	-0.3%	3.0%	0.5%	1.5%	1.7%
Great Plains Energy	7.0%	0.0%		3.5%	0.0%	0.0%	5.0%	1.7%
NSTAR	5.0%	2.5%	1.5%	3.0%	2.5%	3.5%	4.5%	3.5%
Otter Tail	3.5%	2.5%	7.0%	4.3%	2.5%	2.0%	5.0%	3.2%
Pinnacle West Capital	-3.0%	7.0%	4.0%	2.7%	3.5%	5.0%	3.5%	4.0%
PNM Resources	-2.0%	4.5%	5.0%	2.5%	4.5%	7.0%	4.0%	5.2%
SCANA	6.5%	-1.0%	3.0%	2.8%	4.5%	5.5%	6.0%	5.3%
Wisconsin Energy	9.5%	-12.0%	3.5%	0.3%	4.0%	4.5%	6.5%	5.0%
Average	2.9%	0.4%	3.7%	**2.4%**	3.1%	3.5%	4.5%	**3.7%**
omparison Group - Parcell Criteria								
Avista	-6.5%	-11.5%	5.0%	-4.3%	11.0%	6.0%	4.0%	7.0%
Cleco	5.0%	2.5%	4.5%	4.0%	0.5%	0.0%	3.5%	1.3%
Empire District Electric	-3.5%	0.0%	2.0%	-0.5%	8.0%	0.0%	2.0%	3.3%
IDACORP	-3.0%	-3.0%	3.5%	-0.8%	6.0%	-5.0%	3.5%	1.5%
NSTAR	5.0%	2.5%	1.5%	3.0%	2.5%	3.5%	4.5%	3.5%
Puget Energy	-5.5%	-10.5%	0.5%	-5.2%	5.5%	1.0%	2.5%	3.0%
UIL Holdings	-5.0%		2.0%	-1.5%	0.0%	0.0%	0.5%	0.2%
Vectren					4.5%	3.5%	4.0%	4.0%
Average	-1.9%	-3.3%	2.7%	**-0.8%**	4.8%	1.1%	3.1%	**3.0%**
Hawaiian Electric Industries	1.0%	0.0%	2.5%	**1.2%**	2.5%	0.0%	3.0%	**1.8%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group - PUC Criteria								
CH Energy Group	4.8%	2.0%	1.8%	-0.3%	1.7%		1.3%	6.1%
Great Plains Energy	5.5%	2.9%	3.2%	3.5%	1.7%	3.0%	2.8%	8.3%
NSTAR	4.2%	5.0%	4.5%	3.0%	3.5%	5.0%	4.2%	8.4%
Otter Tail	4.6%	4.6%	3.7%	4.3%	3.2%	4.0%	3.9%	8.6%
Pinnacle West Capital	4.5%	4.4%	2.7%	2.7%	4.0%	4.5%	3.6%	8.2%
PNM Resources	2.7%	5.9%	3.7%	2.5%	5.2%	6.0%	4.6%	7.4%
SCANA	4.0%	5.2%	5.2%	2.8%	5.3%	4.5%	4.6%	8.7%
Wisconsin Energy	2.6%	5.3%	6.3%	0.3%	5.0%	5.0%	4.4%	7.0%
Mean	4.1%	4.4%	3.9%	2.4%	3.7%	4.6%	3.7%	**7.8%**
Median								**8.2%**
Composite		8.5%	8.0%	**6.5%**	7.8%	**8.7%**	7.8%	
Comparison Group - Parcell Criteria								
Avista	3.2%	3.8%	3.8%	-4.3%	7.0%	4.5%	3.0%	6.1%
Cleco	4.4%	5.2%	4.5%	4.0%	1.3%	4.0%	3.8%	8.2%
Empire District Electric	5.6%	0.1%	1.5%	-0.5%	3.3%	2.0%	1.3%	6.9%
IDACORP	4.4%	3.3%	3.0%	-0.8%	1.5%	4.5%	2.3%	6.6%
NSTAR	4.2%	5.0%	4.5%	3.0%	3.5%	5.0%	4.2%	8.4%
Puget Energy	4.6%	2.0%	3.0%	-5.2%	3.0%	4.0%	1.4%	5.9%
UIL Holdings	5.6%	1.7%	0.0%	-1.5%	0.2%	1.0%	0.3%	5.9%
Vectren	4.5%	2.3%	3.7%		4.0%	4.0%	3.5%	7.9%
Mean	4.5%	2.9%	3.0%	-0.8%	3.0%	3.6%	2.5%	**7.0%**
Median								**6.8%**
Composite		7.5%	7.5%	**3.8%**	7.5%	**8.2%**	7.0%	
Hawaiian Electric Industries	4.8%	3.1%	2.7%	1.2%	1.8%	3.0%	2.3%	**7.2%**
Composite		**7.9%**	7.5%	**6.0%**	6.7%	7.8%	7.2%	

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
RETURN ON AVERAGE COMMON EQUITY

Year	EPS	BVPS	ROE
1977		$79.07	
1978	$12.33	$85.35	15.00%
1979	$14.86	$94.27	16.55%
1980	$14.82	$102.48	15.06%
1981	$15.36	$109.43	14.50%
1982	$12.64	$112.46	11.39%
1983	$14.03	$116.93	12.23%
1984	$16.64	$122.47	13.90%
1985	$14.61	$125.20	11.80%
1986	$14.48	$126.82	11.49%
1987	$17.50	$134.04	13.42%
1988	$23.75	$141.32	17.25%
1989	$22.87	$147.26	15.85%
1990	$21.73	$153.01	14.47%
1991	$16.29	$158.85	10.45%
1992	$19.09	$149.74	12.37%
1993	$21.89	$180.88	13.24%
1994	$30.60	$193.06	16.37%
1995	$33.96	$216.51	16.58%
1996	$38.73	$237.08	17.08%
1997	$39.72	$249.52	16.33%
1998	$37.71	$266.40	14.62%
1999	$48.17	$290.68	17.29%
2000	$50.00	$325.80	16.22%
2001	$24.69	$338.37	7.43%
2002	$27.59	$321.72	8.36%
2003	$48.73	$367.17	14.15%
2004	$58.55	$414.75	14.98%
Average			**14.01%**

Source: Standard & Poor's Analysts' Handbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET RETURN	CAPM RATES
Comparison Group - PUC Criteria				
CH Energy Group	4.73%	0.75	13.20%	11.1%
Great Plains Energy	4.73%	0.75	13.20%	11.1%
NSTAR	4.73%	0.70	13.20%	10.7%
Otter Tail	4.73%	0.55	13.20%	9.4%
Pinnacle West Capital	4.73%	0.80	13.20%	11.5%
PNM Resources	4.73%	0.80	13.20%	11.5%
SCANA	4.73%	0.65	13.20%	10.2%
Wisconsin Energy	4.73%	0.65	13.20%	10.2%
Mean	4.73%	0.71	13.20%	**10.9%**
Median				**10.9%**
Comparison Group - Parcell Criteria				
Avista	4.73%	0.80	13.20%	11.5%
Cleco	4.73%	1.00	13.20%	13.2%
Empire District Electric	4.73%	0.65	13.20%	10.2%
IDACORP	4.73%	0.80	13.20%	11.5%
NSTAR	4.73%	0.70	13.20%	10.7%
Puget Energy	4.73%	0.70	13.20%	10.7%
UIL Holdings	4.73%	0.70	13.20%	10.7%
Vectren	4.73%	0.75	13.20%	11.1%
Mean	4.73%	0.76	13.20%	**11.2%**
Median				**10.9%**
Hawaiian Electric Industries	4.73%	0.60	13.20%	**9.8%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
CAPM COST RATES
USING IBBOTSON RISK PREMIUM

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Comparison Group - PUC Criteria				
CH Energy Group	4.73%	0.75	6.60%	9.7%
Great Plains Energy	4.73%	0.75	6.60%	9.7%
NSTAR	4.73%	0.70	6.60%	9.4%
Otter Tail	4.73%	0.55	6.60%	8.4%
Pinnacle West Capital	4.73%	0.80	6.60%	10.0%
PNM Resources	4.73%	0.80	6.60%	10.0%
SCANA	4.73%	0.65	6.60%	9.0%
Wisconsin Energy	4.73%	0.65	6.60%	9.0%
Mean	4.73%	0.71	6.60%	**9.4%**
Median				**9.7%**
Comparison Group - Parcell Criteria				
Avista	4.73%	0.80	6.60%	10.0%
Cleco	4.73%	1.00	6.60%	11.3%
Empire District Electric	4.73%	0.65	6.60%	9.0%
IDACORP	4.73%	0.80	6.60%	10.0%
NSTAR	4.73%	0.70	6.60%	9.4%
Puget Energy	4.73%	0.70	6.60%	9.4%
UIL Holdings	4.73%	0.70	6.60%	9.4%
Vectren	4.73%	0.75	6.60%	9.7%
Mean	4.73%	0.76	6.60%	**9.8%**
Median				**9.5%**
Hawaiian Electric Industries	4.73%	0.60	6.60%	**8.7%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	1992-2001 Average	2000-2004 Average	2004	2005	2008-2010
Comparison Group - PUC Criteria																		
CH Energy Group	11.0%	11.1%	10.7%	10.7%	11.3%	10.9%	10.4%	10.2%	10.5%	10.4%	7.0%	9.1%	8.7%	10.7%	9.1%	8.0%	8.0%	9.0%
Great Plains Energy	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	14.2%	11.6%	15.6%	16.6%	16.9%	11.8%	15.0%	13.5%	13.0%	12.0%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.5%	12.6%	12.5%	11.3%	12.3%	13.3%	14.0%	14.0%	13.3%	12.0%	13.4%	13.0%	12.5%	12.5%
Otter Tail	15.0%	15.0%	15.1%	14.7%	14.7%	14.7%	14.0%	14.7%	15.1%	15.1%	15.2%	12.0%	10.9%	14.8%	13.7%	10.5%	10.5%	10.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	11.5%	10.1%	8.5%	8.5%	8.5%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.7%	10.0%	9.3%	8.0%	8.5%	7.5%
SCANA	11.0%	13.5%	11.0%	11.5%	13.3%	11.7%	12.6%	7.8%	10.7%	10.7%	11.7%	12.4%	12.5%	11.4%	11.6%	12.0%	12.0%	11.0%
Wisconsin Energy	11.4%	11.8%	10.5%	12.9%	11.5%	3.2%	10.0%	11.3%	6.4%	10.6%	12.8%	11.8%	9.0%	10.0%	10.1%	10.5%	10.0%	9.5%
Average	10.6%	11.9%	11.6%	11.6%	12.0%	10.8%	11.9%	10.7%	11.5%	12.5%	11.4%	11.4%	10.9%	**11.5%**	**11.5%**	10.5%	10.4%	10 1%
Composite														**11.5%**	**11.5%**			
Comparison Group - Parcell Criteria																		
Avista	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.7%	10.4%	7.4%	6.0%	8.0%	8.0%
Cleco	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	13.4%	13.4%	12.5%	12.5%	11.5%
Empire District Electric	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	9.3%	7.4%	9.0%	10.0%	10.5%
IDACORP	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.5%	12.3%	10.3%	7.5%	8.0%	7.5%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.5%	12.6%	12.5%	11.3%	12.3%	13.3%	14.0%	14.0%	13.3%	12.0%	13.4%	13.0%	12.5%	12.5%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	7.4%	10.4%	8.7%	8.5%	8.5%	9.5%
UIL Holdings	10.8%	10.4%	10.9%	11.8%	10.1%	10.4%	9.5%	11.5%	12.8%	12.1%	8.9%	6.1%	7.5%	11.0%	9.5%	6.0%	6.0%	6.5%
Vectren	13.9%	13.9%	13.8%	13.6%	13.4%	13.6%	13.2%	10.9%	10.0%	8.8%	13.3%	11.6%	10.1%	12.5%	10.8%	11.5%	12.0%	11.5%
Mean	11.7%	11.6%	11.2%	11.4%	11.5%	11.8%	11.7%	10.0%	12.9%	10.4%	9.7%	8.8%	8.7%	**11.4%**	**10.1%**	9.3%	9.7%	9.7%
Composite														**11.4%**	**10.1%**			
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.6%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	10.3%	**11.0%**	**11.1%**	10.0%	10.5%	10.5%

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	1992-2001 Average	2000-2004 Average
Comparison Group - PUC															
CH Energy Group	123%	133%	107%	112%	114%	135%	155%	133%	125%	141%	152%	147%	149%	128%	143%
Great Plains Energy	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	178%	187%
NSTAR	138%	154%	130%	129%	124%	146%	181%	166%	161%	161%	170%	175%	189%	149%	171%
Otter Tail	116%	120%	207%	213%	209%	195%	198%	201%	221%	243%	245%	209%	186%	192%	221%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	131%	136%	132%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	123%	96%	106%
SCANA	161%	168%	157%	166%	175%	164%	195%	145%	134%	135%	137%	158%	170%	160%	147%
Wisconsin Energy	178%	177%	160%	172%	169%	154%	185%	152%	119%	126%	129%	147%	155%	159%	135%
Average	133%	142%	137%	146%	152%	156%	176%	150%	147%	159%	151%	155%	165%	**150%**	**155%**
Composite														**150%**	**155%**
Comparison Group - Parcell															
Avista	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	163%	144%
Cleco	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	176%	181%	182%
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	162%	151%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	127%	168%	149%
NSTAR	138%	154%	130%	129%	124%	146%	181%	166%	161%	161%	170%	175%	189%	149%	171%
Puget Energy	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	135%	141%	135%
UIL Holdings	129%	140%	114%	110%	114%	111%	152%	144%	141%	139%	126%	113%	142%	129%	132%
Vectren	199%	192%	157%	162%	171%	180%	209%	215%	180%	181%	174%	170%	175%	185%	176%
Mean	160%	165%	136%	137%	145%	155%	175%	166%	192%	164%	138%	133%	150%	**160%**	**155%**
˜mposite														**160%**	**155%**
.ıawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	180%	**147%**	**151%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 -2004

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
Averages:		
1992-2001	**14.7%**	**341%**
2000-2004	**12.2%**	**334%**

Source: Standard & Poor's Analyst's Handbook, 2004 edition.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.11	B++	B+
Comparison Group - PUC	1.6	0.71	A	B+
Comparison Group - Parcell	2.6	0.76	B+/B++	B/B+
Hawaiian Electric Industries	2.0	0.60	A	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

HAWAII ELECTRIC COMPANY
TOTAL COST OF CAPITAL

ITEM	Amount ($000)	PERCENT		COST RATE			WEIGHTED COST	
Short-Term Debt	$37,429	3.25%		3.50%			0.11%	
Long-Term Debt	$423,565	36.81%		6.25%			2.30%	
Hybrid Securities	$27,303	2.37%		7.55%			0.18%	
Preferred Equity	$20,476	1.78%		5.54%			0.10%	
Common Equity	$641,955	55.79%	8.50%		10.00%	4.74%		5.58%
Total	$1,150,728	100.00%				**7.43%**		**8.27%**
							7.85% Mid-point	

HAWAII ELECTRIC COMPANY
PRE-TAX COVERAGE

ITEM	AMOUNT ($000)	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST
Short-Term Debt	$37,429	2.68%	3.50%	0.09%	0.09%
Long-Term Debt	$423,565	30.38%	6.25%	1.90%	1.90%
Purchased Power (1)	$243,404	17.46%	10.00%	1.75%	1.75%
Hybrid Securities	$27,303	1.96%	7.55%	0.15%	0.15%
Preferred Equity	$20,476	1.47%	5.54%	0.08%	0.13%
Common Equity	$641,955	46.05%	9.25%	4.26%	6.55%
TOTAL CAPITAL	$1,394,132	100.00%		8.23%	10.56%

() Average 2005 Purchase Power "debt equivalent" from HECO-WP-2116, page 11

Pre-tax coverage = 10.56% / (0.09% +1.90%+1.75%)
2.83 X

Standard & Poor's Utility Benchmark Ratios:

	BBB
Pre-tax coverage (X)	
Business Position:	
6	2.6 - 4.0 x
Total Debt to Total Capital (%)	
Business Position	
6	48 - 58 %

Note: Pre-tax coverage benchmarks from S&P Utility Financial Targets as of 1999. Total debt to total capital benchmarks from S&P Revised Financial Guidelines as of 2004.

RISK PREMIUM BY DECADE AS DERIVED BY HECO WITNESS MORIN

Year	Risk Premium	Risk Premium By Decade
1932	-20.37%	
1933	-22.28%	
1934	-30.96%	
1935	71.96%	
1936	13.43%	
1937	-37.34%	
1938	13.83%	
1939	3.41%	-1.04%
1940	-25.19%	
1941	-33.29%	
1942	20.18%	
1943	53.84%	
1944	3.82%	
1945	43.63%	
1946	9.75%	
1947	-14.20%	
1948	5.21%	
1949	16.09%	7.98%
1950	6.86%	
1951	20.65%	
1952	16.29%	
1953	6.40%	
1954	22.40%	
1955	9.15%	
1956	8.14%	
1957	1.03%	
1958	41.89%	
1959	7.74%	14.06%
1960	7.08%	
1961	33.87%	
1962	-6.76%	
1963	8.37%	
1964	12.92%	
1965	2.06%	
1966	-7.99%	
1967	4.29%	
1968	9.84%	
1969	-10.62%	5.31%
1970	-0.96%	
1971	-10.42%	
1972	-2.33%	
1973	-13.90%	
1974	-28.22%	
1975	44.10%	
1976	11.53%	
1977	12.11%	
1978	-3.13%	
1979	5.54%	1.43%
1980	12.09%	
1981	15.32%	
1982	3.24%	
1983	10.46%	
1984	8.71%	
1985	-1.40%	
1986	2.80%	
1987	-5.07%	
1988	7.14%	
1989	10.96%	6.43%
1990	-2.18%	
1991	9.55%	
1992	-3.49%	
1993	-4.86%	
1994	-7.34%	
1995	0.98%	
1996	3.11%	
1997	6.25%	
1998	8.36%	
1999	-10.15%	0.02%
2000	50.09%	
2001	-5.54%	

Source: Calculations made from data contained on HECO-2002.

WORKPAPERS

OF

DAVID C. PARCELL

COMPANY		MARKET CAP ($000)	NET PLANT ($000)	TOTAL REVENUES ($000)	ELECTRIC REVENUES (%)	COMMON EQUITY RATIO	SAFETY	BETA	FIN STR	S&P STOCK RANKING	MOODY'S BOND RATING	S&P BOND RATING	COAL	OIL	GAS	NUCLEAR	HYDRO	PURCH
Alliant Energy	WPL, IES & ISP	$3,100,000	$4,805,000	$2,958,700	65%	50.5%	3	0.80	B+	B	A2	A-	58%		*	14%		28%
Allegheny Energy		$2,600,000	$6,303,000	$2,756,100	58%	22.6%	4	1.65	C++	C	Ba1	BB	67%	1%	23%		9%	
Ameren	Un El & CIPSCO	$9,400,000	$11,085,000	$5,160,000	87%	53.0%	1	0.75	A+	A-	A2	A-	85%			13%		
American Electric Power	AEP & C&SW	$13,000,000	$22,790,000	$14,057,000	48%	43.5%	3	1.15	B++	B	Baa1	BBB						
Aquila	UtiliCorp	$975,000	$2,777,400	$1,711,000	40%	32.7%	5	1.30	C	C	B2	B-	33%	14%	13%			40%
Avista	Wash Water Pwr	$850,000	$1,976,200	$1,148,700	89%	40.8%	3	0.90	B	B	Baa3	BBB-					39%	44%
Black Hills		$975,000	$1,460,000	$1,120,000	15%	47.0%	3	0.95	B+	B+	Baa1	BBB	80%	5%	5%			10%
CMS Energy	Cons En	$2,500,000	$8,636,000	$5,472,000	39%	21.5%	4	1.35	C++	C	Baa3	BBB-	70%			21%		8%
CH Energy Group	Cen Hud	$725,000	$745,100	$791,500	56%	59.1%	1	0.80	A	A-	A2	A					4%	96%
CenterPoint Energy	HL&P	$3,600,000	$11,750,000	$8,510,400	24%	6.5%	4	0.60	C++	B	Baa2	BBB						
Central Vermont Public Service		$265,000	$290,000	$302,200	100%	60.0%	3	0.50	B++	B	NR	BBB+				50%	33%	
CINergy	CG&E & PSI Res	$7,400,000	$9,929,500	$4,668,000	64%	49.0%	2	0.85	A	B+	Baa3	BBB-	87%		8%			5%
Cleco	Cen La Elec	$990,000	$1,060,100	$745,800	76%	53.0%	3	1.10	B+	B+	A3	BBB+	32%	9%	9%			50%
Consolidated Edison		$10,300,000	$15,830,000	$6,758,000	69%	51.0%	1	0.60	A++	B+	A1	A						100%
Constellation Energy Group	BG&E	$8,900,000	$4,228,800	$12,549,700	22%	48.6%	2	0.90	A	B	A1	A	32%	7%	7%	52%		
DPL	Dayton P&L	$3,100,000	$2,525,000	$1,189,800	99%	32.0%	3	0.95	B	B+	Baa3	BBB-	65%					
Duquesne Light Holdings	Duquesne Light	$1,400,000	$1,465,000	$897,300	87%	35.5%	4	0.80	B	B	Baa1	BBB+	Sold generation assets in 2000					
Dominion Resources	VA Power	$23,000,000	$26,716,000	$13,972,000	54%	42.0%	2	0.85	B++	B+	A2	A-	39%	5%		29%		23%
DTE Energy	Detroit Edison	$7,700,000	$10,491,000	$7,114,000	18%	42.8%	3	0.70	B+	B+	Baa2	BBB+	71%			16%		12%
Duke Energy		$25,000,000	$33,506,000	$22,503,000	23%	49.1%	3	1.10	B++	B+	Baa2	BBB	49%			46%		5%
Edison International	So. Cal Edison	$10,600,000	$13,185,000	$11,270,000	75%	34.5%	4	0.90	C++	B	A3	BBB	15%			25%	3%	57%
El Paso Electric		$925,000	$1,280,000	$700,000	99%	47.0%	3	0.65	B+	B	Baa2	BBB	9%		27%	50%		14%
Empire District Electric		$600,000	$857,000	$325,500	93%	48.7%	3	0.70	B+	B	Baa1	A-	46%	10%	10%		1%	33%
Energy East	NYSEG, RG&E, CMP	$3,800,000	$5,825,000	$4,757,000	66%	40.5%	2	0.85	B++	B+	Baa1	BBB+						near 100%
Entergy		$15,500,000	$18,900,000	$10,124,000	81%	53.0%	2	0.75	A	B+	Baa2	A-	18%	15%	15%	52%		
Exelon	PECO & Comm Ed	$29,100,000	$21,482,000	$14,515,000	65%	43.5%	2	0.70	A	B+	A2	A-				52%		37%
FPL Group		$14,300,000	$20,605,000	$10,522,000	83%	48.5%	1	0.70	A+	A-	Aa3	A		6%	55%	9%		
FirstEnergy	Oh Ed, Cle El & Tol	$13,000,000	$13,478,000	$12,453,000	78%	45.6%	3	0.75	B+	B+	Baa1	BBB						
Great Plains Energy	KCP&L	$2,200,000	$2,734,500	$2,464,000	51%	53.4%	2	0.80	A	B	A2	BBB	73%	1%	1%	22%		4%
Green Mountain Power		$150,000	$235,000	$228,000	100%	52.0%	3	0.60	B++	B	Baa1	BBB		3%	1%	37%	35%	19%
Hawaiian Electric Industries		$2,400,000	$2,395,000	$1,915,000	78%	52.0%	2	0.65	A	B+	Baa2	BBB		61%				39%
IDACORP	Idaho Power	$1,200,000	$2,200,000	$830,000	92%	50.5%	3	0.85	B+	B	A3	A-	53%				47%	
MDU Resources Group	Montana Dak Util	$3,200,000	$2,385,000	$2,719,300	8%	64.5%	1	0.85	A+	A	A2	A-	71%	1%				28%
MGE Energy		$700,000	$607,400	$424,900	61%	62.6%	1	0.60	A	B+	Aa3	AA-	65%		2%			33%
NiSource	NIPSCO	$6,100,000	$9,384,700	$6,666,200	18%	49.3%	3	0.80	B+	B	Baa2	BBB	77%					23%
Northeast Utilities		$2,400,000	$5,864,200	$6,686,700	126%	34.0%	3	0.75	B+	B	A3	BBB+		*		*	*	*
NSTAR	Boston Edison	$2,900,000	$3,580,000	$2,954,300	83%	40.0%	1	0.70	A	B+	A1	A	Sold generation assets in 1998 & 1999					
OGE Energy		$2,400,000	$3,581,000	$4,926,600	40%	47.4%	3	0.70	B++	A-	Baa2	BBB+	59%		25%			16%
Otter Tail		$725,000	$682,100	$882,300	44%	60.7%	2	0.60	A	A-	A2	A-	42%					57%
PG&E	Pacific G & E	$15,000,000	$18,565,000	$10,630,000	71%	51.5%	4	1.00	C++	B	Baa2	BBB				34%	61%	
PPL Corp		$10,200,000	$11,209,000	$5,812,000	70%	37.9%	3	0.95	B+	B	Baa1	A-						
Pinnacle West Capital	Ariz Pub Ser	$3,800,000	$7,620,000	$2,918,600	66%	50.0%	1	0.85	A	A	Baa1	BBB	20%		11%	15%		54%
Pepco Holdings	Pepco & Conectiv	$4,100,000	$7,060,000	$7,000,000	55%	42.5%	3	0.85	B	B	A3	A-						
Progress Energy	CP&L & Fl Prog	$10,300,000	$14,615,000	$9,630,000	69%	44.5%	2	0.80	B++	A-	A2	BBB	16%	16%	16%	44%		
Public Service Enterprise Group	PSE&G	$12,400,000	$13,070,000	$10,986,000	56%	31.5%	3	0.85	B+	B+	A3	A-						
PNM Resources	P S of New Mexico	$1,500,000	$2,210,000	$1,560,000	75%	53.0%	2	0.85	B++	B+	Baa2	BBB	68%	1%	1%	30%		
Puget Energy	Puget Sound Energy	$2,400,000	$4,135,000	$2,500,000	62%	42.5%	3	0.75	B+	B	Baa2	BBB	19%	2%	1%		5%	73%
SCANA	SCE&G	$4,300,000	$6,762,000	$3,885,000	43%	42.6%	2	0.75	A	B	A1	A-	64%	2%	1%	20%	5%	8%
Sempra Energy	San Diego G & E	$8,800,000	$10,945,000	$8,800,000	44%	52.0%	2	0.80	A	B	A1	A+				23%		77%
Sierra Pacific Resources	Nev Pwr & SP Pwr	$1,200,000	$5,015,000	$2,800,000	94%	26.0%	4	1.00	C+	C	Ba2	BB+	23%	11%	10%			56%
Southern Company		$23,500,000	$28,975,000	$11,903,000	81%	44.0%	2	0.65	A	A-	A1	A+	66%		9%	15%	4%	6%
TECO Energy	Tampa Elec	$3,100,000	$4,657,900	$2,598,300	53%	24.9%	3	0.90	B	B-	Baa2	BBB-	99%					
TXU		$22,600,000	$21,065,000	$9,308,000	19%	5.0%	3	1.00	B	B	Baa1	BBB						
UniSource Energy	Tucson Elec	$1,100,000	$2,060,000	$1,200,000	93%	22.0%	3	0.65	C++	B	Ba2	BBB-	76%	12%	12%			
UIL Holdings	United Illum	$700,000	$560,000	$1,101,300	63%	50.0%	3	0.80	B+	B+	Baa2	NR						
Vectren	Ind Ener & SIGCORP	$2,000,000	$2,130,000	$1,689,800	69%	50.5%	2	0.75	A	B+	A3	A-						
WPS Resources		$2,000,000	$1,880,000	$4,890,600	19%	51.5%	2	0.75	B++	B+	Aa2	AA-	61%			18%	2%	19%
Westar Energy	KP&L	$1,900,000	$3,911,000	$1,464,500	89%	45.5%	3	0.80	B++	B	Ba1	BBB	56%		33%	9%		
Wisconsin Energy		$4,000,000	$5,903,100	$3,431,100	49%	43.3%	2	0.70	B++	B	A1	A-	61%			24%	2%	13%
Xcel Energy	Nor States Pwr	$7,300,000	$14,085,000	$8,345,300	63%	44.5%	2	0.80	B++	B	A3	A-	51%	6%	6%	12%		25%

CH ENERGY GROUP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		23.77				
1976	2.68	24.72	20.8	17.5	11.1%	79%
1977	2.90	25.72	22.5	19.1	11.5%	82%
1978	3.04	26.28	22.1	19.8	11.7%	81%
1979	3.27	27.51	20.8	18.0	12.2%	72%
1980	3.38	26.49	19.9	15.0	12.5%	65%
1981	3.72	26.51	19.0	16.0	14.0%	66%
1982	3.91	26.78	24.8	17.1	14.7%	79%
1983	3.94	27.40	26.1	21.5	14.5%	88%
1984	4.43	27.91	25.6	16.1	16.0%	75%
1985	4.67	29.49	31.3	23.0	16.3%	95%
1986	4.49	31.18	39.9	26.6	14.8%	110%
1987	2.66	20.35	31.9	16.5	10.3%	94%
1988	2.63	21.24	21.9	16.9	12.6%	93%
1989	2.28	21.76	24.1	20.4	10.6%	103%
1990	2.38	22.31	24.9	20.0	10.8%	102%
1991	2.40	22.84	29.0	22.6	10.6%	114%
1992	2.55	23.60	31.3	25.9	11.0%	123%
1993	2.68	24.65	35.8	28.4	11.1%	133%
1994	2.68	25.33	30.4	22.9	10.7%	107%
1995	2.74	25.96	31.9	25.4	10.7%	112%
1996	2.99	26.87	31.5	28.8	11.3%	114%
1997	2.97	27.61	43.9	29.8	10.9%	135%
1998	2.90	28.00	47.1	38.9	10.4%	155%
1999	2.88	28.73	45.0	30.4	10.2%	133%
2000	3.05	29.38	46.3	26.1	10.5%	125%
2001	3.11	30.33	45.9	38.3	10.4%	141%
2002	2.12	30.31	52.4	39.9	7.0%	152%
2003	2.78	30.80	49.7	40.2	9.1%	147%
2004	2.69	31.31	49.6	43.1	8.7%	149%

GREAT PLAINS ENERGY

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		10.65				
1976	1.17	10.85	10.0	8.4	10.9%	86%
1977	1.00	10.93	10.8	9.4	9.2%	93%
1978	1.18	11.00	9.9	8.0	10.8%	82%
1979	1.00	10.65	9.1	7.4	9.2%	76%
1980	1.45	10.56	7.9	6.1	13.7%	66%
1981	1.61	11.12	8.3	6.5	14.9%	68%
1982	1.39	10.98	9.4	7.3	12.6%	76%
1983	2.08	11.76	11.4	8.4	18.3%	87%
1984	2.24	12.64	10.3	7.1	18.4%	71%
1985	2.21	13.55	12.3	9.0	16.9%	81%
1986	1.40	13.90	16.1	11.1	10.2%	99%
1987	1.51	14.22	15.6	10.5	10.7%	93%
1988	1.60	13.10	16.1	12.4	11.7%	104%
1989	1.66	13.50	18.1	14.1	12.5%	121%
1990	1.66	13.75	17.9	14.6	12.2%	119%
1991	1.58	13.90	23.8	17.1	11.4%	148%
1992	1.35	13.79	24.5	19.9	9.8%	160%
1993	1.66	13.99	26.3	21.8	12.0%	173%
1994	1.64	14.13	23.9	18.6	11.7%	151%
1995	1.92	14.50	26.6	21.5	13.4%	168%
1996	1.69	14.71	29.4	23.6	11.6%	181%
1997	1.69	14.19	29.9	27.4	11.7%	198%
1998	1.89	14.41	31.8	28.0	13.2%	209%
1999	1.26	13.97	29.6	20.8	8.9%	178%
2000	2.05	14.88	29.0	20.9	14.2%	173%
2001	1.59	12.59	27.6	23.2	11.6%	185%
2002	2.04	13.58	27.0	15.7	15.6%	163%
2003	2.27	13.82	32.8	21.4	16.6%	198%
2004	2.46	15.35	35.7	27.9	16.9%	218%

NSTAR

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		15.89				
1976	1.36	16.07	13.7	11.2	8.5%	78%
1977	1.03	15.27	14.2	12.4	6.6%	85%
1978	1.48	15.50	13.1	11.1	9.6%	79%
1979	1.76	15.19	12.4	9.9	11.5%	73%
1980	1.88	15.51	12.3	9.3	12.2%	70%
1981	2.08	16.01	12.3	9.8	13.2%	70%
1982	1.59	15.86	13.1	10.0	10.0%	72%
1983	1.80	16.10	14.8	12.5	11.3%	85%
1984	2.43	16.85	17.8	12.4	14.7%	92%
1985	2.52	17.71	23.1	16.8	14.6%	115%
1986	2.58	19.38	27.9	21.2	13.9%	132%
1987	1.97	19.37	28.0	16.8	10.2%	116%
1988	1.86	19.38	18.8	12.5	9.6%	81%
1989	1.90	16.73	22.1	15.4	10.5%	104%
1990	1.60	17.22	20.3	16.5	9.4%	108%
1991	1.96	17.92	24.9	18.3	11.2%	123%
1992	2.10	18.77	28.3	22.3	11.4%	138%
1993	2.28	19.42	32.6	26.4	11.9%	154%
1994	2.41	20.11	29.9	21.5	12.2%	130%
1995	2.08	20.61	29.5	23.1	10.2%	129%
1996	2.61	21.09	30.1	21.8	12.5%	124%
1997	2.71	21.96	38.4	24.6	12.6%	146%
1998	2.76	22.27	44.9	35.1	12.5%	181%
1999	2.77	26.57	44.6	36.4	11.3%	166%
2000	3.19	25.31	47.0	36.4	12.3%	161%
2001	3.27	23.81	45.2	33.9	13.3%	161%
2002	3.38	24.50	48.2	34.0	14.0%	170%
2003	3.50	25.67	49.0	38.7	14.0%	175%
2004	3.51	27.05	54.4	45.3	13.3%	189%

OTTER TAIL POWER

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		5.26				
1976	0.61	5.34	5.4	4.3	11.4%	91%
1977	0.71	5.62	5.7	5.0	13.0%	98%
1978	0.83	5.90	5.6	4.7	14.4%	89%
1979	0.87	6.14	5.7	4.9	14.4%	88%
1980	0.64	5.92	5.4	4.3	10.5%	80%
1981	0.43	5.54	4.9	3.9	7.5%	76%
1982	0.73	5.66	5.7	4.3	13.0%	88%
1983	0.80	5.86	6.5	5.3	13.9%	102%
1984	0.88	6.08	7.1	5.8	14.7%	108%
1985	0.89	6.34	8.8	6.8	14.3%	126%
1986	0.90	6.48	12.3	8.2	14.0%	160%
1987	0.86	6.55	12.5	8.4	13.1%	160%
1988	0.96	6.77	5.6	4.6	14.4%	77%
1989	0.97	6.92	6.1	4.7	14.2%	79%
1990	1.00	6.87	6.7	5.5	14.5%	88%
1991	1.08	7.13	8.2	6.2	15.4%	103%
1992	1.09	7.36	9.1	7.7	15.0%	116%
1993	1.12	7.62	10.3	7.7	15.0%	120%
1994	1.17	7.90	17.4	14.8	15.1%	207%
1995	1.19	8.24	18.9	15.4	14.7%	213%
1996	1.24	8.61	19.3	15.9	14.7%	209%
1997	1.29	8.96	19.2	15.0	14.7%	195%
1998	1.29	9.47	21.4	15.1	14.0%	198%
1999	1.45	10.30	22.8	17.0	14.7%	201%
2000	1.60	10.87	29.0	17.8	15.1%	221%
2001	1.68	11.33	31.0	23.0	15.1%	243%
2002	1.79	12.25	34.9	22.8	15.2%	245%
2003	1.51	12.98	28.9	23.8	12.0%	209%
2004	1.50	14.61	27.5	23.8	10.9%	186%

PINNACLE WEST

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		19.98				
1976	2.47	20.64	19.9	15.0	12.2%	86%
1977	3.02	21.83	21.4	18.1	14.2%	93%
1978	3.15	22.56	21.6	18.8	14.2%	91%
1979	2.90	22.75	21.4	16.9	12.8%	85%
1980	2.75	21.97	19.6	14.6	12.3%	76%
1981	3.26	22.13	19.6	15.1	14.8%	79%
1982	3.30	22.94	25.1	18.0	14.6%	96%
1983	3.46	23.78	26.5	17.8	14.8%	95%
1984	3.65	24.18	22.6	14.5	15.2%	77%
1985	3.88	25.36	28.1	20.6	15.7%	98%
1986	3.04	25.84	32.0	26.0	11.9%	113%
1987	3.21	26.62	32.8	26.4	12.2%	113%
1988	2.15	23.46	29.8	15.0	8.6%	89%
1989	1.44	16.31	16.4	5.0	7.2%	54%
1990	0.81	17.40	18.6	9.4	4.8%	83%
1991	-3.90	15.23	17.9	9.6	-23.9%	84%
1992	1.73	17.00	20.5	16.8	10.7%	116%
1993	1.95	18.87	25.3	19.6	10.9%	125%
1994	1.99	20.32	22.8	16	10.2%	99%
1995	2.22	21.49	28.9	19.6	10.6%	116%
1996	2.47	22.51	32.3	26.3	11.2%	133%
1997	2.76	23.90	42.8	27.6	11.9%	152%
1998	2.85	25.50	49.3	39.4	11.5%	180%
1999	3.18	26.00	43.4	30.2	12.3%	143%
2000	3.35	28.09	52.7	25.7	12.4%	145%
2001	3.68	29.46	50.7	37.7	12.8%	154%
2002	2.53	29.44	46.7	21.7	8.6%	116%
2003	2.52	31.0	40.5	28.3	8.3%	114%
2004	2.58	31.65	45.8	36.3	8.2%	131%

PNM RESOURCES

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		13.86				
1976	1.44	14.04	16.3	11.7	10.3%	100%
1977	1.64	14.40	16.0	13.3	11.5%	103%
1978	1.89	14.57	14.9	12.3	13.0%	94%
1979	1.98	14.84	14.3	11.6	13.5%	88%
1980	2.24	15.57	14.5	10.2	14.7%	81%
1981	2.22	15.93	16.6	12.9	14.1%	94%
1982	2.15	16.24	18.7	14.4	13.4%	103%
1983	1.86	16.80	19.7	15.2	11.3%	106%
1984	2.07	16.85	17.7	13.0	12.3%	91%
1985	2.20	17.15	20.5	15.9	12.9%	107%
1986	2.19	17.67	25.3	18.7	12.6%	126%
1987	1.33	17.12	26.2	11.6	7.6%	109%
1988	1.31	12.02	14.9	7.3	9.0%	76%
1989	1.15	12.01	10.6	7.2	9.6%	74%
1990	0.21	11.57	10.3	5.3	1.8%	66%
1991	0.21	11.79	7.7	5.1	1.8%	55%
1992	0.50	10.00	9.4	6.3	4.6%	72%
1993	0.81	8.86	9.3	6.5	8.6%	84%
1994	1.11	10.08	9.1	7.3	11.7%	87%
1995	0.91	11.22	12.2	8.1	8.5%	95%
1996	1.15	12.04	13.7	11.5	9.9%	108%
1997	1.25	12.84	15.8	10.5	10.0%	106%
1998	1.50	13.75	16.5	11.6	11.3%	106%
1999	1.29	14.74	14.3	9.9	9.1%	85%
2000	1.55	15.76	18.9	9.8	10.2%	94%
2001	2.61	17.25	25.2	15.3	15.8%	123%
2002	1.07	16.60	20.5	11.5	6.3%	95%
2003	1.15	17.84	19.6	12.6	6.7%	93%
2004	1.40	18.60	26.1	18.7	7.7%	123%

SCANA CORP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		16.62				
1976	0.99	8.55	9.8	7.7	7.8%	69%
1977	1.11	8.92	10.5	8.7	12.7%	110%
1978	1.13	9.22	9.5	8.0	12.5%	96%
1979	0.95	9.24	9.0	7.2	10.3%	88%
1980	1.01	9.26	8.5	6.0	10.9%	78%
1981	1.22	9.31	8.0	6.3	13.1%	77%
1982	1.16	9.14	9.6	7.3	12.6%	91%
1983	1.15	9.17	10.7	8.8	12.6%	106%
1984	1.43	9.66	11.8	8.6	15.2%	108%
1985	1.41	10.00	14.1	11.1	14.3%	128%
1986	1.52	10.38	21.4	13.6	14.9%	171%
1987	1.60	10.82	20.0	13.3	15.1%	157%
1988	1.50	11.11	16.9	14.3	13.7%	142%
1989	1.52	11.39	17.9	14.8	13.5%	145%
1990	1.66	12.28	17.9	15.1	14.0%	139%
1991	1.69	12.62	22.1	16.8	13.6%	156%
1992	1.42	13.23	22.4	19.3	11.0%	161%
1993	1.86	14.30	26.1	20.1	13.5%	168%
1994	1.60	14.69	25.1	20.5	11.0%	157%
1995	1.70	15.00	28.6	20.6	11.5%	166%
1996	2.05	15.86	28.6	25.3	13.3%	175%
1997	1.90	16.66	29.9	23.4	11.7%	164%
1998	2.12	16.86	37.3	27.9	12.6%	195%
1999	1.44	20.27	32.6	21.1	7.8%	145%
2000	2.12	19.40	31.1	22.0	10.7%	134%
2001	2.15	20.95	30.0	24.3	10.7%	135%
2002	2.38	19.64	32.1	23.5	11.7%	137%
2003	2.50	20.82	35.7	28.1	12.4%	158%
2004	2.67	21.80	39.7	32.8	12.5%	170%

WISCONSIN ENERGY CORP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		5.70				
1976	0.71	5.99	7.1	5.4	12.1%	107%
1977	0.75	6.27	7.3	6.2	12.2%	110%
1978	0.78	6.56	6.9	5.6	12.2%	97%
1979	0.83	6.83	6.0	5.0	12.4%	82%
1980	0.78	6.96	6.0	4.3	11.3%	75%
1981	0.98	7.25	6.5	4.5	13.8%	77%
1982	1.20	7.78	8.6	5.8	16.0%	96%
1983	1.32	8.40	9.5	7.3	16.3%	104%
1984	1.45	9.06	11.2	8.4	16.6%	112%
1985	1.58	9.88	13.5	10.3	16.7%	126%
1986	1.58	10.58	21.5	12.8	15.4%	168%
1987	1.70	11.30	19.3	14.0	15.5%	152%
1988	1.94	12.18	18.6	15.0	16.5%	143%
1989	1.92	13.01	21.4	16.8	15.2%	152%
1990	1.85	13.70	21.7	17.8	13.9%	148%
1991	1.87	14.35	26.4	20.0	13.3%	165%
1992	1.67	14.97	28.5	23.8	11.4%	178%
1993	1.81	15.67	29.4	24.8	11.8%	177%
1994	1.67	16.01	27.5	23.1	10.5%	160%
1995	2.13	16.89	30.9	25.8	12.9%	172%
1996	1.97	17.42	32.0	26.0	11.5%	169%
1997	0.54	16.51	29.1	23.0	3.2%	154%
1998	1.65	16.46	34.0	27.0	10.0%	185%
1999	1.88	16.89	31.6	19.1	11.3%	152%
2000	1.08	17.00	23.6	16.8	6.4%	119%
2001	1.84	17.81	24.6	19.1	10.6%	126%
2002	2.32	18.44	26.5	20.2	12.8%	129%
2003	2.26	19.92	33.7	22.6	11.8%	147%
2004	1.85	21.31	34.6	29.5	9.0%	155%

AVISTA

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		10.43				
1976	1.51	11.09	13.2	9.8	14.0%	107%
1977	1.19	11.36	12.8	10.3	10.6%	103%
1978	1.60	11.94	12.2	10.2	13.7%	96%
1979	1.39	12.23	11.8	9.5	11.5%	88%
1980	1.17	11.78	10.3	7.6	9.7%	75%
1981	1.65	11.45	9.2	7.8	14.2%	73%
1982	1.59	11.27	10.8	8.5	14.0%	85%
1983	1.51	11.34	11.4	9.3	13.4%	92%
1984	1.35	11.22	10.3	8.0	12.0%	81%
1985	1.52	11.49	12.6	9.3	13.4%	96%
1986	1.03	10.44	15.8	12.1	9.4%	127%
1987	1.16	10.43	15.1	11.1	11.1%	126%
1988	1.27	10.49	14.2	11.7	12.1%	124%
1989	1.35	10.61	15.7	13.0	12.8%	136%
1990	1.40	10.84	15.5	13.4	13.1%	135%
1991	1.31	11.11	16.9	14.2	11.9%	142%
1992	1.32	11.54	18.4	15.9	11.7%	151%
1993	1.44	12.02	21.0	17.4	12.2%	163%
1994	1.28	12.45	18.9	13.6	10.5%	133%
1995	1.41	12.82	18.1	13.5	11.2%	125%
1996	1.35	12.70	19.9	17.1	10.6%	145%
1997	1.96	13.38	24.8	17.4	15.0%	162%
1998	1.28	11.76	24.9	16.1	10.2%	163%
1999	0.12	10.69	19.6	14.6	1.1%	152%
2000	1.74	15.34	68.0	14.6	13.4%	317%
2001	1.20	15.12	24.0	10.6	7.9%	114%
2002	0.67	14.84	16.6	8.8	4.5%	85%
2003	1.02	15.54	18.7	9.8	6.7%	94%
2004	0.73	15.70	19.4	15.4	4.7%	111%

CLECO

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
1976						
1977	0.23	2.57				
1978	0.28	3.27				
1979	1.48	6.14				
1980	0.95	3.65				
1981	0.62	4.39	3.7	3.5		90%
1982	0.54	4.59	3.9	3.2	12.0%	79%
1983	0.72	4.82	4.9	3.7	15.3%	91%
1984	0.92	5.23	5.6	4.4	18.3%	100%
1985	0.91	5.62	7.6	5.3	16.8%	119%
1986	0.81	5.98	9.5	7.2	14.0%	144%
1987	0.88	6.23	9.3	7.2	14.4%	135%
1988	0.90	6.56	8.5	7.7	14.1%	127%
1989	0.89	6.87	9.0	3.9	13.3%	96%
1990	0.93	7.16	9.1	7.9	13.3%	121%
1991	0.96	6.76	12.3	8.6	13.8%	150%
1992	0.97	7.06	13.1	11.4	14.0%	177%
1993	0.89	7.29	13.6	11.5	12.4%	175%
1994	0.96	7.56	12.8	10.4	12.9%	156%
1995	1.04	7.91	14.1	11.0	13.4%	162%
1996	1.12	8.30	14.6	12.6	13.8%	168%
1997	1.09	8.68	16.6	12.4	12.8%	171%
1998	1.12	9.07	18.1	14.3	12.6%	183%
1999	1.19	9.44	17.8	14.1	12.9%	172%
2000	1.46	10.04	28.3	15.1	15.0%	223%
2001	1.51	10.69	27.3	19.2	14.6%	224%
2002	1.52	11.77	24.9	9.7	13.5%	154%
2003	1.26	10.09	18.4	11.0	11.5%	134%
2004	1.32	10.90	20.8	16.2	12.6%	176%

EMPIRE DISTRICT

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		6.93				
1976	0.79	7.03	8.2	6.8	11.3%	107%
1977	0.92	7.28	8.7	7.5	12.9%	113%
1978	0.85	7.39	7.9	6.6	11.6%	99%
1979	0.86	7.49	7.3	5.6	11.6%	87%
1980	0.79	7.50	6.5	5.0	10.5%	77%
1981	0.67	7.35	5.8	4.9	9.0%	72%
1982	1.06	7.59	7.2	5.1	14.2%	82%
1983	1.26	8.01	8.7	6.8	16.2%	99%
1984	1.48	8.63	9.9	7.4	17.8%	104%
1985	1.38	9.14	12.3	9.3	15.5%	122%
1986	1.43	9.67	18.0	11.6	15.2%	157%
1987	1.48	10.22	17.0	13.7	14.9%	154%
1988	1.53	10.75	15.9	13.8	14.6%	142%
1989	1.47	11.17	16.1	13.3	13.4%	134%
1990	1.28	11.75	15.8	13.6	11.2%	128%
1991	1.43	12.08	24.1	14.8	12.0%	163%
1992	1.26	12.29	24.8	20.1	10.3%	184%
1993	1.16	12.37	24.8	19.1	9.4%	178%
1994	1.32	12.47	20.5	15.0	10.6%	143%
1995	1.18	12.69	19.8	16.0	9.4%	142%
1996	1.21	12.96	19.5	17.1	9.4%	143%
1997	1.29	13.06	20.0	15.8	9.9%	138%
1998	1.53	13.43	26.1	18.4	11.6%	168%
1999	1.13	13.48	26.8	20.7	8.4%	177%
2000	1.35	13.65	30.8	18.9	10.0%	183%
2001	0.59	13.58	26.6	17.5	4.3%	162%
2002	1.19	14.59	22.0	15.1	8.4%	132%
2003	1.29	15.17	22.5	17.0	8.7%	133%
2004	0.86	14.76	23.5	19.5	5.7%	144%

IDACORP

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		13.71				
1976	1.54	14.19	14.5	11.8	11.0%	94%
1977	1.10	14.20	15.1	13.0	7.7%	99%
1978	1.48	14.44	15.6	13.0	10.3%	100%
1979	1.21	14.26	13.8	12.0	8.4%	90%
1980	1.52	14.07	13.2	10.1	10.7%	82%
1981	1.53	14.26	11.9	9.1	10.8%	74%
1982	2.36	15.01	14.6	10.3	16.1%	85%
1983	2.25	15.77	17.4	14.3	14.6%	103%
1984	2.81	16.74	19.3	15.4	17.3%	107%
1985	2.16	17.29	24.5	18.8	12.7%	127%
1986	2.00	17.46	30.9	22.8	11.5%	155%
1987	1.30	17.29	30.3	19.0	7.5%	142%
1988	1.32	16.81	25.4	19.5	7.7%	132%
1989	2.37	17.35	30.0	22.0	13.9%	152%
1990	1.91	17.40	29.4	22.8	11.0%	150%
1991	1.56	17.06	28.8	24.3	9.1%	154%
1992	1.55	17.28	28.8	24.4	9.0%	155%
1993	1.97	17.86	33.0	27.3	11.2%	172%
1994	1.80	17.91	30.6	21.8	10.1%	146%
1995	2.10	18.15	30.0	23.4	11.6%	148%
1996	2.21	18.47	34.3	27.3	12.1%	168%
1997	2.32	18.93	37.8	28.5	12.4%	177%
1998	2.37	19.42	38.1	29.9	12.4%	177%
1999	2.43	20.02	36.5	26.0	12.3%	158%
2000	3.50	21.82	53.0	25.9	16.7%	189%
2001	3.35	23.15	49.4	33.6	14.9%	185%
2002	1.63	23.01	41.0	20.9	7.1%	134%
2003	0.96	22.54	30.2	20.6	4.2%	112%
2004	1.95	23.45	32.9	25.3	8.5%	127%

PUGET ENERGY

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		16.99				
1976	1.92	17.99	16.8	12.7	11.0%	84%
1977	1.88	18.36	18.4	15.5	10.3%	93%
1978	2.17	18.63	18.3	15.6	11.7%	92%
1979	1.67	17.93	17.5	13.6	9.1%	85%
1980	1.60	17.15	15.1	11.0	9.1%	74%
1981	2.86	17.44	14.3	11.5	16.5%	75%
1982	2.29	17.42	16.9	12.4	13.1%	84%
1983	1.93	17.04	16.5	13.1	11.2%	86%
1984	1.52	15.42	15.0	9.3	9.4%	75%
1985	2.07	15.70	18.4	12.6	13.3%	100%
1986	1.74	15.29	25.3	17.6	11.2%	138%
1987	2.13	15.50	22.5	17.8	13.8%	131%
1988	2.14	15.98	20.3	18.0	13.6%	122%
1989	2.13	16.12	22.5	18.0	13.3%	126%
1990	2.16	16.52	22.5	18.6	13.2%	126%
1991	2.21	16.96	26.9	19.1	13.2%	137%
1992	2.16	17.76	27.9	23.9	12.4%	149%
1993	2.00	18.65	29.8	23.5	11.0%	146%
1994	1.64	18.43	24.9	16.5	8.8%	112%
1995	1.89	18.48	24.0	20.1	10.2%	119%
1996	1.89	18.53	26.0	22.1	10.2%	130%
1997	1.28	16.06	30.2	23.5	7.4%	155%
1998	1.85	16.00	30.3	24.1	11.5%	170%
1999	1.91	16.24	28.4	18.6	11.8%	146%
2000	2.16	16.61	28.0	19.1	13.2%	143%
2001	1.22	15.66	27.8	18.5	7.6%	143%
2002	1.24	16.27	23.6	16.6	7.8%	126%
2003	1.22	16.71	24.4	18.1	7.4%	129%
2004	1.25	16.95	24.8	20.5	7.4%	135%

UIL HOLDINGS

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		27.95				
1976	2.97	28.42	27.1	22.6	10.5%	88%
1977	3.77	29.70	29.8	25.6	13.0%	95%
1978	3.06	29.36	28.9	22.5	10.4%	87%
1979	3.94	30.59	25.8	20.3	13.1%	77%
1980	3.56	29.09	23.3	17.0	11.9%	68%
1981	4.24	28.64	20.8	17.8	14.7%	67%
1982	5.39	29.90	26.4	18.6	18.4%	77%
1983	5.67	31.48	29.0	19.1	18.5%	78%
1984	5.40	33.80	23.9	9.0	16.5%	50%
1985	5.82	37.15	27.1	13.8	16.4%	58%
1986	5.97	40.50	36.3	26.9	15.4%	81%
1987	5.99	44.02	34.0	21.3	14.2%	65%
1988	7.54	34.11	27.5	19.1	19.3%	60%
1989	5.31	26.11	34.3	24.6	17.6%	98%
1990	3.55	27.35	34.1	26.9	13.3%	114%
1991	3.22	28.84	39.1	30.0	11.5%	123%
1992	3.17	30.12	42.0	34.1	10.8%	129%
1993	3.13	30.06	45.9	38.5	10.4%	140%
1994	3.28	30.39	40.0	28.8	10.9%	114%
1995	3.64	31.20	38.6	29.4	11.8%	110%
1996	3.16	31.20	40.0	31.1	10.1%	114%
1997	3.27	31.56	46.0	23.8	10.4%	111%
1998	3.00	31.74	54.2	41.7	9.5%	152%
1999	3.71	32.59	53.6	38.9	11.5%	144%
2000	4.26	34.03	56.0	37.9	12.8%	141%
2001	4.21	35.42	53.0	43.8	12.1%	139%
2002	3.09	33.80	58.9	28.2	8.9%	126%
2003	2.07	34.42	46.1	30.8	6.1%	113%
2004	2.57	33.75	54.7	41.8	7.5%	142%

VECTREN

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		4.05				
1976	0.62	4.36	4.7	5.1	14.7%	117%
1977	0.75	4.83	5.3	4.5	16.3%	107%
1978	0.76	5.22	5.1	4.4	15.1%	95%
1979	0.57	5.41	4.9	4.1	10.7%	85%
1980	0.86	5.83	4.7	3.5	15.3%	73%
1981	0.83	6.18	4.9	3.9	13.8%	74%
1982	0.86	6.50	6.4	4.7	13.6%	87%
1983	1.07	7.00	7.5	6.1	15.9%	101%
1984	1.25	7.62	8.5	6.4	17.1%	102%
1985	1.13	8.09	10.4	8.3	14.4%	119%
1986	1.19	8.44	15.5	9.6	14.4%	152%
1987	1.28	8.48	15.5	11.6	15.1%	160%
1988	1.48	9.45	15.1	12.9	16.5%	156%
1989	1.41	9.94	16.1	13.8	14.5%	154%
1990	1.51	9.70	16.7	13.9	15.4%	156%
1991	1.58	10.24	22.6	15.6	15.8%	192%
1992	1.51	11.42	22.8	20.3	13.9%	199%
1993	1.63	11.98	23.7	21.3	13.9%	192%
1994	1.69	12.55	22.6	16.0	13.8%	157%
1995	1.76	13.32	24.3	17.6	13.6%	162%
1996	1.83	14.00	24.7	21.9	13.4%	171%
1997	1.95	14.77	30.1	21.6	13.6%	180%
1998	2.01	15.70	36.9	26.9	13.2%	209%
1999	1.48	11.55	36.1	22.6	10.9%	215%
2000	1.17	11.91	26.5	15.8	10.0%	180%
2001	1.08	12.53	24.4	19.8	8.8%	181%
2002	1.68	12.79	26.1	18.0	13.3%	174%
2003	1.56	14.18	26.1	19.7	11.6%	170%
2004	1.44	14.45	27.1	22.9	10.1%	175%

HAWAIIAN ELECTRIC

Year	EPS	BVPS	Hi Pr	Lo Pr	ROE	M/B
		6.18				
1976	0.74	6.47	6.1	5.0	11.6%	87%
1977	0.79	6.73	6.7	5.8	12.0%	95%
1978	0.85	7.05	7.1	6.0	12.3%	95%
1979	0.92	7.39	6.9	5.9	12.7%	89%
1980	0.95	7.51	6.2	4.6	12.7%	72%
1981	0.98	7.66	6.7	5.2	12.9%	78%
1982	0.59	7.92	7.7	5.9	7.6%	87%
1983	1.03	8.16	8.5	6.8	12.8%	95%
1984	1.13	8.50	10.7	7.8	13.5%	111%
1985	1.20	8.92	12.7	9.8	13.8%	129%
1986	1.29	9.48	17.8	12.3	14.0%	163%
1987	1.43	9.80	17.2	11.2	14.8%	147%
1988	1.45	10.98	16.8	13.0	14.0%	143%
1989	1.53	11.59	20.2	14.7	13.6%	154%
1990	1.01	11.65	20.0	13.7	8.7%	145%
1991	1.20	12.18	19.0	14.7	10.1%	141%
1992	1.27	11.06	22.3	17.4	10.9%	171%
1993	1.19	11.62	19.4	15.5	10.5%	154%
1994	1.30	11.90	18.3	14.9	11.1%	141%
1995	1.33	12.25	19.9	16.1	11.0%	149%
1996	1.30	12.52	19.8	16.6	10.5%	147%
1997	1.38	12.77	20.8	16.4	10.9%	147%
1998	1.48	12.87	21.3	18.2	11.5%	154%
1999	1.45	13.16	20.3	14.0	11.1%	132%
2000	1.27	12.72	19.0	13.8	9.8%	127%
2001	1.60	13.06	20.6	16.8	12.4%	145%
2002	1.62	14.21	24.5	17.3	11.9%	153%
2003	1.58	14.36	24.0	19.1	11.1%	151%
2004	1.50	14.80	29.5	23.0	10.3%	180%

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Comparison Group - PUC						
CH Energy Group	1	0.75	A	4.00	A-	3.67
Great Plains Energy	2	0.75	A	4.00	B	3.00
NSTAR	1	0.70	A	4.00	B+	3.33
Otter Tail	2	0.55	A	4.00	A-	3.67
Pinnacle West Capital	1	0.80	A	4.00	A-	4.00
PNM Resources	2	0.80	B++	3.67	B+	3.33
SCANA	2	0.65	A	4.00	B	3.00
Wisconsin Energy	2	0.65	B++	3.67	B	3.00
Average	1.6	0.71	A	3.92	B+	3.38
Comparison Group - Parcell						
Avista	3	0.80	B	3.00	B	3.00
Cleco	3	1.00	B+	3.33	B+	3.33
npire District Electric	3	0.65	B+	3.33	B	3.00
JACORP	3	0.80	B+	3.33	B	3.00
NSTAR	1	0.70	A	4.00	B+	3.33
Puget Energy	3	0.70	B+	3.33	B	3.00
UIL Holdings	3	0.70	B+	3.33	B+	3.33
Vectren	2	0.75	A	4.00	B+	3.33
Average	2.6	0.76	B+/B++	3.46	B/B+	3.17
Hawaiian Electric Industries	2	0.6	A	4.00	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Automobile & Components						
Harley-Davidson	3	1.1	B++	3.67	A+	4.33
Johnson Controls	2	1	A	4	A+	4.33
Ford Motor	3	1.25	B	3	B	3
General Motors	3	1.25	B++	3.67	B	3
Goodyear Tire & Rubber	4	1.5	C+	2.33	B-	2.67
Dana	3	1.6	B+	3.33	B-	2.67
Delphi	3	1.15	B	3	B	3
Cooper Tire & Rubber	3	1	B++	3.67	B+	3.33
Visteon	4	1.35	?		NR	
Consumer Durables & Apparel						
Pulte Homes	3	1.2	A	4	A	4
Coach	3	1.25	A	4	NR	
Nike	3	0.9	A+	4.33	A	4
KB Home	3	1.2	A	4	A	4
Centex	3	1.3	B++	3.67	A+	4.33
Black & Decker	3	1.05	B+	3.33	B+	3.33
Fortune Brands	2	0.8	A	4	B	3
Brunswick	3	1.2	B++	3.67	B	3
VF	3	0.95	B++	3.67	A-	3.67
Liz Claiborne	1	0.95	A+	4.33	A	4
Stanley Works	3	1	B++	3.67	B+	3.33
Reebok International	3	1.05	A	4	B	3
Mattel	3	0.75	B++	3.67	B+	3.33
Whirlpool	3	1.25	B++	3.67	B	3
Legget and Platt	2	1.05	A	4	B+	3.33
Hasbro	3	0.95	B+	3.33	B	3
Eastman Kodak	3	1.1	B+	3.33	B-	2.67
Snap-on	2	1	C++	2.67	B	3
Jones Apparel Group	3	1.1	B++	3.67	B+	3.33
Newell Rubbermaid	3	0.85	B+	3.33		
Maytag	4	1.4	C++	2.67	B	3
Hotels, Restaurants & Leisure						
Carnival	3	1.25	B+	3.33	A+	4.33
Starbucks	3	0.8	A	4	B+	3.33
McDonald's	1	1	A++	4.67	A	4
Marriot Intl.	3	1			B+	3.33
YUM! Brands	3	0.6	B+	3.33	NR	
Starwood Hotels & Resorts	3	1.25	B	3	NR	
Intl. Game Technology	3	0.95	B+	3.33	B+	3.33
Harrah's Entertainment	3	0.95	B	3	B	3
Hilton Hotels	3	1.15	B	3	B	3
Darden Restaurants	3	0.85	A	4	A-	3.67
Wendy's Intl.	2	0.75	A	4	A-	3.67
Media						
Walt Disney	3	1.35	A	4	B	3
McGraw-Hill	1	0.75	A+	4.33	54	

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Omnicom Group	3	1.25	B++	3.67	A+	4.33
Univision Communications	3	1.55	B+	3.33	NR	
Gannett	1	0.9	A++	4.67	A	4
Comcast	3	1.35			B-	2.67
Meredith	3	0.85	B+	3.33	A-	3.67
Time Warner	3	1.55	B++	3.67	NR	
Tribune	1	0.9	A+	4.33	B+	3.33
Knight-Ridder	1	0.85	A+	4.33	A-	3.67
Clear Channel Communications	3	1.5	B	3	B-	2.67
New York Times	2	0.9	A	4	A-	3.67
Viacom	3	1.45	B+	3.33	B-	2.67
Dow Jones	2	1.05	B++	3.67	B	3
Interpublic Group	3	1.35	B	3	C	2
News Corp	3	1.3	B+	3.33	NR	
Retailing						
eBay	3	1.5	A+	4.33	NR	
Staples	3	1.35	A	4	B+	3.33
Lowe's	3	1.1	A+	4.33	A+	4.33
Nordstrom	3	1.2	B+	3.33	B+	3.33
Best Buy	3	1.3	A	4	B	3
Home Depot	2	1.25	A++	4.67	A+	4.33
Bed Bath & Beyond	2	1.2	A++	4.67	A-	3.67
Gap	3	1.25	A	4	A	4
J.C. Penny	3	1.1	B++	3.67	B-	2.67
Sherwin-Williams	2	1.05	A	4	A	4
OfficeMax					B-	2.67
Dollar General	3	1.15	B+	3.33	A+	4.33
TJX	3	1.05	A+	4.33	A+	4.33
Target	3	1.15	A	4	A+	4.33
Kohl's	3	1.05	A	4	B+	3.33
Limited Brands	3	1.15	A	4	B+	3.33
Genuine Parts	1	0.9	A++	4.67	A	4
Office Depot	3	1.25	A	4	B+	3.33
Auto Zone	3	0.8	B	3	B+	3.33
Tiffany	3	1.6	A	4	A	4
Family Dollar Stores	3	1.05	A	4	A+	4.33
Circuit City Stores	3	1.35	B	3	B-	2.67
AutoNation	3	1.05	B++	3.67	B	3
Federated Department Stores	3	1.25	B+	3.33	B	3
RadioShack	3	1.2	A	4	B+	3.33
Dillard's	3	1.2	B	3	B+	3.33
May Department Stores	3	1.15	B+	3.33	B+	3.33
Toys 'R' Us	3	1.3	B+	3.33	B-	2.67
Sears, Roebuck	3	1.3	B++	3.67	NR	
Big Lots	3	1.1	B++	3.67	B-	2.67
Food & Staples Retailing						
CVS	3	0.85	A+	4.33	B	3

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Walgreen	1	0.8	A++	4.67	A+	4.33
Costco Wholesale	3	1	A	4	B+	3.33
Sysco	1	0.8	A++	4.67	A+	4.33
Wal-Mart Stores	1	0.85	A++	4.67	A+	4.33
Supervalu	3	0.85	B++	3.67	A-	3.67
Albertson's	3	0.8	A	4	A-	3.67
Safeway	3	0.95	B++	3.67	B	3
Kroger	3	1.1	B+	3.33	B	3
Food, Beverage & Tobacco						
Archer Daniels Midland	3	0.7	B+	3.33	B+	3.33
PepsiCo	1	0.65	A++	4.67	A+	4.33
Wm. Wrigley Jr.	1	0.6	A++	4.67	A+	4.33
Altria Group	3	0.75	B+	3.33	A+	4.33
Hershey Foods	1	0.6	A++	4.67	A-	3.67
Kellogg	2	0.55	B++	4.67	B+	3.33
General Mills	1	0.55	A	4	B	3
Coca-Cola	1	0.6	A++	4.67	B+	3.33
Reynold's American	3	0.9	B	3	NR	
UST	3	0.9	B+	3.33	A-	3.67
Sara Lee	1	0.6	A	4	A-	3.67
McCormick	2	0.5	B++	3.67	A+	4.33
Brown-Forman	1	0.65	A+	4.33	A	4
Anheuser-Busch	1	0.6	A++	4.67	A+	4.33
H.J. Heinz	1	0.55	A+	4.33	B+	3.33
Pepsi Bottling Group	3	0.6	B	3	NR	
Cambell Soup	2	0.6	B++	3.67	B+	3.33
Molson Coors Brewing	3	0.5	B+	3.33	A	4
ConAgra Foods	2	0.7	A	4	A	4
Coca-Cola Enterprises	1	0.6	A++	4.67	B	3
Household & Personal Products						
Proctor & Gamble	1	0.55	A++	4.67	A	4
Gillette	1	0.65	B+	3.33	A-	3.67
Avon Products	3	0.6	B+	3.33	A	4
Alberto-Culver	1	0.7	B++	3.67	B+	3.33
Kimberly-Clark	1	0.65	A++	4.67	A	4
Colgate-Palmolive	1	0.65	A++	4.67	A+	4.33
Clorox	2	0.65	B++	3.67	A	4
Energy						
Conoco-Phillips	2	0.85	A	4	B	3
CheveronTexaco	1	0.8	A++	4.67	B+	3.33
Valero Energy	3	1.1	B++	3.67	B+	3.33
Occidental Petroleum	1	0.85	A+	4.33	B+	3.33
Exxon Mobil	1	0.8	A++	4.67	A-	3.67
Apache	3	0.85	B++	3.67	B+	3.33
Devon Energy	3	0.9	B++	3.67	B+	3.33
Sunoco	2	1	A	4	A-	3.67

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Burlington Resources	3	0.8	B++	3.67	B	3
EOG Resources	3	0.9	B++	3.67	B	3
XTO Energy	3	0.8	B+	3.33	B+	3.33
Unocal	2	0.9	A	4	B+	3.33
Anadarko Petroleum	3	0.9	B+	3.33	B+	3.33
Marathon Oil	2	0.85	B++	3.67	B+	3.33
Amerada Hess	3	0.9	B++	3.67	B	3
Halliburton	3	1.2	B	3	B	3
BJ Services	3	1.15	B	3	B	3
Baker Hughes	3	0.95	B++	3.67	B	3
Sclumberger	3	1.05	B++	3.67	B-	2.67
Ashland	2	0.8	B+	3.33	B	3
Kerr-McGee	3	1	B+	3.33	B	3
Kinder Morgan	2	0.7	B+	3.33	B	3
Nabors Industries	3	1.1	B++	3.67	B	3
Transocean	3	1.05	B+	3.33	B-	2.67
Williams	5	2.45	C++	2.67	B	3
Noble	3	0.9	B	3	B	3
Rowan	3	1.1	B	3	B-	2.67
El Paso	5	1.9	C+	2.33	NR	
Banks						
Bank Of America	2	1.2	A+	4.33	A-	3.67
Wachovia	3	1.1	B++	3.67	A-	3.67
Countrywide Financial	3	1	B++	3.67	A	4
Wells Fargo	1	0.95	A+	4.33	A	4
U.S. Bancorp	3	1.2	B++	3.67	B+	3.33
National City	2	1.05	A	4	A	4
Golden West Financial	2	0.85	B++	3.67	A+	4.33
Regions Financial	2	1.05	A	4	A-	3.67
North Fork Bancorporation	2	0.95	B++	3.67	A	4
BB&T	1	0.95	A	4	A-	3.67
M&T Bank	1	0.95	A	4	A+	4.33
Marshall & Ilsley	1	1	A	4	A	4
Sovereign Bancorp	3	1.1	B	3	B+	3.33
PNC Financial Services Group	2	1.1	B++	3.67	NR	
Synovus Financial	2	1.1	B++	3.67	A+	4.33
Sun Trust Banks	2	1.05	B++	3.67	A+	4.33
KeyCorp	3	1.05	B+	3.33	A-	3.67
Compass Bancshares					A+	4.33
Zions Bancorporation	3	1.05	B++	3.67	A	4
Washington Mutual	2	0.95	A	4	A	4
MGIC Investment	3	1.2	B++	3.67	A	4
First Horizon National	2	0.9	B++	3.67	A+	4.33
Comerica	2	1.05	A	4	A	4
AmSouth Bancorporation	2	0.95	A	4	A-	3.67
Huntington Bancshares	3	0.95	B	3	B+	3.33
Fifth Third Bancorp	1	1	A+	4.33	A+	4.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Freddie Mac	3	0.95	A	4	A+	4.33
Fannie Mae	3	0.85	B+	3.33	NR	
Diversified Financials						
Franklin Resources	3	1.25	B++	3.67	A-	3.67
T. Rowe Price Group					A	4
Moody's	2	0.8	B+	3.33	B+	3.33
Capital One Financial	3	1.65	A	4	A+	4.44
Goldman Sachs Group	2	1.35	A+	4.33	NR	
American Express	2	1.5	A+	4.33	A-	3.67
Lehman Brothers Holdings	3	1.45	B+	3.33	A	4
SLM	1	0.75	A+	4.33	A-	3.67
Merril Lynch	3	1.55	A+	4.33	A-	3.67
Bear Stearns	3	1.25	A	4	A	4
Providan Financial	5	1.9	C++	2.67	B	3
MBNA	3	1.55	A+	4.33	A+	4.33
Citigroup	3	1.45	A	4	A+	4.33
JPMorgan Chase	3	1.5	B+	3.33	B	3
Morgan Stanley	3	1.7	A+	4.33	A-	3.67
Principal Financial Group	2	1	B++	3.67	NR	
Bank of New York	3	1.3	A	4	A-	3.67
E*Trade Financial	3	2.05	B+	3.33	B-	2.67
Mellon Financial	3	1.35	B++	3.67	A-	3.67
Federated Investors	2	0.95	A	4	B+	2.67
State Street	3	1.35	A	4	A	4
Charles Schwab	3	1.8	A	4	B+	3.33
Northern Trust	3	1.45	A	4	A-	3.67
CIT Group	3	1.35	B+	3.33	NR	
Janus Capital Group	3	1.75	B+	3.33	NR	
Insurance						
Progressive	3	1.05	A	4	B+	3.33
Chubb	2	1.1	A	4	B+	3.33
Allstate	2	0.95	A	4	B+	3.33
AFLAC					A	4
XL Capital	3	1.05	A	4	B	3
MetLife	2	1.1	A	4	NR	
Hartford Financial Services Group	3	1.25	B++	3.67	B	3
Prudential Financial	2	1.1	A	4	NR	
American International Group	3	1.2	A	4	A+	4.33
ACE					B	3
Cincinnati Financial	2	0.9	B++	3.67	A-	3.67
Safeco	3	0.95	B+	3.33	B	3
Ambac Financial Group	2	1.1	A	4	A+	4.33
St. Paul Travelers	3	1.2	B++	3.67	NR	
Aon	3	1.2	A	4	B+	3.33
Jefferson-Pilot	1	0.9	A+	4.33	A+	4.33
Torchmark	2	1	A	4	A	4
Lincoln National	2	1.25	A+	4.33	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Loews	3	1.05	B++	3.67	B-	2.67
MBIA	2	1.15	A	4	A+	4.33
UnumProvident	3	1.35	B+	3.33	B-	2.67
Marsh & McLennan	3	1.2	B++	3.67	A-	3.67
Real Estate						
Plum Creek Timber	2	0.8	B+	3.33	NR	
Simon Property Group	2	0.7	B++	3.67	B+	3.33
Archstone-Smith Trust	3	0.65	B++	3.67	NR	
ProLogis	2	0.6	B+	3.33	B+	3.33
Equity Residential	2	0.75	B+	3.33	B+	3.33
Equity Office Properties Trust	2	0.7	B+	3.33	NR	
Apartment Investment & Mgmnt.	3	0.65	B	3	B	3
Health-Care Equipment & Sevices						
UnitedHealth Group	2	0.65	A+	4.33	A	4
Caremark Rx	3	0.9	A	4	B-	2.67
Boston Scientific	3	0.75	B++	3.67	B	3
WellPoint	2	0.75	A	4	NR	
Zimmer Holdings	2	0.75	A	4	NR	
Medtronic	1	0.85	A+	4.33	A-	3.67
C.R. Bard	2	0.75	A	4	B+	3.33
Aetna	3	0.95	A	4	NR	
St. Jude Medical	3	0.85	B++	3.67	B	3
Humana	3	1	B+	3.33	B	3
Express Scripts	3	1.05	A	4	B+	3.33
Stryker	2	0.7	A	4	B+	3.33
Fisher Scientific Intl.	3	0.8	C++	2.67	B-	2.67
Cigna					B+	3.33
Quest Diagnostics	3	0.9	B	3	B-	2.67
Waters	3	1.05	B+	3.33	B	3
Becton Dickinson	1	0.75	A+	4.33	A	4
Biomet	3	0.8	A	4	A-	3.67
Bausch & Lomb	3	1	A	4	B	3
Guidant	3	0.75	A	4	B	3
Health Management Assoc.	3	0.75	B+	3.33	A-	3.67
AmerisourceBergen	3	0.75	B+	3.33	A-	3.67
HCA	3	0.6	B+	3.33	B	3
McKesson	3	0.85	B	3	B	3
Laboratory Corp. of Amerca Hldgs.	3	0.95	B	3	B	3
Medco Health Solutions	3	nmf	A	4	NR	
Cardinal Health	3	0.9	A	4	A+	4.33
IMS health	2	0.95	A+	4.33	B+	3.33
Manor Care	3	0.8	B+	3.33	B	3
Thermo Electron	3	1.1	B++	3.67	B-	2.67
PerkinElmer	3	1.15	B	3	B	3
Hospira					NR	
Millipore	3	1	A	4	B	3
Baxter Intl.	2	0.6	A+	4.33	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Tenet Healthcare	4	0.8	C++	2.67	C	2
Pharmaceuticals & Biotechnology						
Johnson & Johnson	1	0.65	A++	4.67	A+	4.33
Gilead Sciences	3	1.05	B	3	B-	2.67
Pfizer	1	0.8	A++	4.67	A	4
Abbot Laboratories					A	4
Forest Laboratories	3	0.8	A	4	B+	3.33
Amgen	2	0.95	A++	4.67	B	3
Genzyme General	3	1.25	B+	3.33	B	3
Allegran	2	0.8	A+	4.33	B	3
Merck	3	0.8	A	4	A+	4.33
Eli Lilly	2	0.7	A++	4.67	B+	3.33
Bristol-Myers Squibb	3	0.95	A	4	A-	3.67
Wyeth	2	0.85	A+	4.33	B	3
Biogen Idec	3	1.2	B+	3.33	C	2
Watson Pharmaceuticals	3	0.75	A	4	B	3
Applied Biosystems Group	3	1.4	A	4	B	3
Mylan Laboratories	3	0.65	A	4	A-	3.67
Schering-Plough	3	0.9	A+	4.33	A-	3.67
Chiron	3	1.15	B++	3.67	B-	2.67
King Pharmaceuticals	3	1.05	B++	3.67	NR	
MedImmune	3	1.25	A+	4.33	C	2
Capital Goods						
Paccar	3	1.2	A	4	B+	3.33
Caterpeillar	2	1.2	A	4	B+	3.33
Cummins	3	1.35	B+	3.33	B-	2.67
Deere	2	1.05	A	4	B	3
Danaher	2	1	B++	3.67	A	4
Eaton	1	1.1	A+	4.33	B+	3.33
3M					?	
Rockwell Automation	2	1.1	A	4	B+	3.33
United Technologies	1	1.15	A++	4.67	?	
Lockheed Martin	2	0.65	A	4	B-	2.67
Illinois Tool Works	2	1.05	A+	4.33	A+	4.33
Rockwell Collins	3	1.1	B++	3.67	NR	
L-3 Communication Holdings					NR	
Masco	3	1.1	A	4	A-	3.67
Ingersoll-Rand	2	1.4	A	4	A	4
Parker Hannifin	3	1.15	B++	3.67	A-	3.67
General Dynamics	1	0.8	A++	4.67	A-	3.67
Northrop Grumman	3	0.65	B+	3.33	B+	3.33
ITT Industries	1	0.9	A	4	B+	3.33
Tyco International	3	1.6	B	3	B-	2.67
Emerson Electric	1	1.1	A++	4.67	A	4
Dover	2	1.2	A	4	A-	3.67
Raytheon	3	0.75	B+	3.33	B-	2.67
General Electric	1	1.3	A++	4.67	A+	4.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Boeing	3	1.05	B++	3.67	B+	3.33
American Standard	3	0.95	B+	3.33	B-	2.67
Cooper Industries	3	1.2	A	4	B+	3.33
W.W. Grainger	2	1.15	A+	4.33	A-	3.67
Flour	3	1.2	A	4	B	3
American Power Conversion	1	1.3	B+	3.33	B+	3.33
Textron	3	1.2	A	4	B+	3.33
Pall	2	1.05	A	4	B	3
Honeywell International	3	1.3	A+	4.33	B	3
Goodrich	3	1.25	B+	3.33	B	3
Navistar International	3	1.45	C++	2.67	C	2
Power-One	4	2.1	C++	2.67	?	
Commercial Services & Supplies						
Cendant	3	1.45	B+	3.33	B	3
Apollo Group	3	0.75	A	4	B+	3.33
R.R. Donnelley	2	0.95	B++	3.67	B	3
Robert Half International	3	1.45	A	4	B	3
Waste Management	3	0.95	B	3	B	3
Equifax	3	1.05	B	3	B+	3.33
Monster Worldwide	4	1.95	B	3	B-	2.67
H&R Block	3	1.1	A	4	A-	3.67
Avery Dennison	2	0.95	A	4	A	4
Pitney Bowes	2	0.9	A	4	A-	3.67
Cintas	3	1.1	B++	3.67	A+	4.33
Allied Waste Industries	4	1.2	C++	2.67	C	2
Transportation						
FedEX	3	1.1	B++	3.67	B+	3.33
United Parcell Service	1	0.8	A+	4.33	NR	
Norfolk Southern	3	1.05	B	3	B	3
Burlington Northern Santa Fe	3	0.95	B+	3.33	A-	3.67
Ryder System	3	1.1	B++	3.67	B	3
CSX	3	1	B++	3.67	B-	2.67
Union Pacific	3	0.9	B+	3.33	B	3
Southwest Airlines	3	1.15	B+	3.33	A-	3.67
Delta Airlines					C	2
Software & Services						
Yahoo!	3	1.9	B+	3.33	B-	2.67
Autodesk	3	1.2	B++	3.67	B	3
Adobe Systems					B+	3.33
Symantec	3	1.05	B++	3.67	B	3
Electronic Arts	3	1.15	A+	4.33	B+	3.33
Microsoft	2	1.15	A++	4.67	B+	3.33
First Data	2	1	A+	4.33	A	4
Oracle	3	1.3	A+	4.33	B	3
Fiserve	3	1.1	B++	3.67	B+	3.33
Mercury Interactive	3	1.85	B+	3.33	B	3
SunGard Data Systems	3	1.1	A	4	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Computer Sciences	3	1.1	A	4	B+	3.33
Citrix Systems	3	1.8	B++	3.67	B+	3.33
Paychex	3	1.15			A+	4.33
Veritas Software	3	1.7	B++	3.67	B-	2.67
Automatic Data Processing	1	0.95	A++	4.67	A+	4.33
Affiliated Computer Services	3	1.1	A	4	B+	3.33
Intuit	3	1.15	A	4	B-	2.67
Novell	4	1.6	B	3	C	2
Parametric Technology	5	1.55	C++	2.67	C	2
Sabre Holdings	3	1.4	B+	3.33	B	3
Computer Associates Intl.	3	1.7	B	3	B-	2.67
Electronic Data Systems	4	1.5	B	3	B	3
Compuware	4	1.55	B	3	NR	
BMC Software	3	1.5	B++	3.67	C	2
Convergys	3	1.4	B++	3.67	NR	
Unisys	4	1.4	C++	2.67	B-	2.67
Siebel Systems	3	1.85	B++	3.67	B-	2.67
Semiconductors & Semiconductor Equipment						
Intel	3	1.4			A	4
Applied Materials	3	1.55	A	4	B-	2.67
Texas Instruments	3	1.6	A+	4.33	B	3
Maxim Integrated Products	3	1.65	A	4	B+	3.33
Altera	3	1.65	B+	3.33	B	3
National Semiconductor	3	1.4	B+	3.33	B-	2.67
Analog Devices	3	1.75	B++	3.67	B	3
Linear Technology	3	1.55	A	4	A	4
Xilinx	3	1.8	B++	3.67	B	3
KLA-Tencor	3	1.6	B+	3.33	B	3
Broadcom	3	1.85	B++	3.67	C	2
NVIDIA					B-	2.67
Advanced Micro Devices					C	2
Micron Technology	4	1.75	C++	2.67	C	2
Novellus Systems	3	1.65	A	4	B-	2.67
Freescale Semiconductor					NR	
Teradyne	4	1.95	B	3	C	2
PMC-Sierra	5	2.3	C++	2.67	C	2
Applied Micro Circuits	4	2.1	B	3	NR	
LSI Logic	4	2.05	B	3	C	2
Technology Hardware & Equipment						
Qualcomm	3	1.15	A	4	B	3
Apple Computer	3	1.05	A	4	B-	2.67
Dell	3	1.2	A++	4.67	B+	3.33
Cisco Systems	3	1.45	A++	4.67	B+	3.33
Network Appliance	4	1.95	B+	3.33	B	3
Hewlett-Packard	3	1.4	A+	4.33	A-	3.67
Lexmark International	3	1.15	B++	3.67	B+	3.33
Motorola	3	1.3	B+	3.33	B+	3.33

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Jabil Circuit	3	1.85	B++	3.67	B	3
NCR	3	1.15	B+	3.33	B-	2.67
IBM	2	1.1	A++	4.67	A-	3.67
EMC	3	1.55	A	4	B	3
Xerox	3	1.45	B	3	B	3
Avaya	4	1.3	B	3	NR	
Qlogic	3	1.9	A	4	B+	3.33
Molex	3	1.3	A	4	A-	3.67
Scientific-Atlanta	3	1.4	B+	3.33	A-	3.67
Symbol Technologies	3	1.5	B+	3.33	B-	2.67
Andrew	3	1.4	B+	3.33	B	3
Sanmina-SCI	4	1.85	C++	2.67	C	2
Tektronix	3	1.3	B++	3.67	B-	2.67
Agilent Technologies	3	1.6	B++	3.67	NR	
Converse Technology	4	1.65	B	3		
Solectron	4	1.8	B+	3.33	C	2
Corning	4	1.5	C++	2.67	C	2
ADC Telecommunications					B	3
Lucent Technologies	5	1.65	C+	2.33	C	2
Sun Microsystems	4	1.6	B	3	C	2
Tellabs	3	1.4	B+	3.33	C	2
Gateway	4	1.3	C++	2.67	C	2
JDS Uniphase	4	1.65	C++	2.67	C	2
Ciena	5	1.85	C+	2.33	NR	
Materials						
Nucor	3	1.25	A+	4.33	B	3
Phelps Dodge	3	1.25	B++	3.67	B-	2.67
United States Steel	3	1.35	B++	3.67	B-	2.67
Dow Chemical	3	1.15	B++	3.67	B	3
Weyerhaeuser	3	1.15	B++	3.67	B	3
Ball	3	0.9	B++	3.67	B+	3.33
Louisiana-Pacific	3	1.4	B	3	B-	2.67
Newmont Mining	3	0.45	B	3	B-	2.67
PPG Industries	2	1.1	A	4	B	3
Praxair	3	1	B++	3.67	A-	3.67
Air Products & Chemicals	2	0.95	B++	3.67	B+	3.33
Rohm & Haas	3	1.15	B+	3.33	A-	3.67
Ecolab	2	0.9	B++	3.67	A	4
DuPont	1	1	A++	4.67	B	3
Sigma-Aldrich	2	0.8	A	4	A+	4.33
Alcoa	3	1.4	A	4	B+	3.33
Eastman Chemical	3	1.05	B+	3.33	B-	2.67
Intl. Flavors & Fragrances	2	0.75	B++	3.67	B	3
Bemis	1	0.95	A+	4.33	A	4
Georgia-Pacific	3	1.45	C++	2.67	B-	2.67
Freeport-McMoRan Copper & Gold	3	1.05	B+	3.33	B	3
Allegheny Technologies	3	1.6	B	3	B-	2.67

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Temple-Inland	3	1.2	B+	3.33	B	3
Vulcan Materials	1	1.05	A	4	A-	3.67
International Paper	3	1.15	B+	3.33	B-	2.67
Englehard	2	1.05	B++	3.67	B+	3.33
Sealed Air	3	0.8	B	3	NR	
Pactiv	3	0.85	B+	3.33	NR	
MeadWestvaco	3	1.1	B	3	B-	2.67
Great Lakes Chemical	3	1.05	B+	3.33	B	3
Hercules	3	1	B	3	B-	2.67
Monsanto	3	0.9	B	3	NR	
Telecommunication Services						
Nextel Communications	4	1.75	B+	3.33	B-	2.67
Verizon Communications	3	1	A+	4.33	B	3
Sprint	3	1.1	B	3	B	3
Alltel	2	1	A	4	B+	3.33
CenturyTel	3	1.1	B++	3.67	A	4
BellSouth	2	1	A+	4.33	A-	3.67
SBC Communications	2	1.05	A+	4.33	B+	3.33
Citizens Communications	3	1	B	3	B-	2.67
AT&T					B	3
Qwest Communicaitons Intl.	5	1.7	C+	2.33	C	2
Utilities						
Constellation Energy Group	2	0.9	A	4	B	3
PG&E	4	1.05	C++	2.67	B	3
Sempra Energy	2	0.95	A	4	B	3
Dominion Resources	2	0.85	B++	3.67	B+	3.33
Exelon	2	0.7	A	4	B+	3.33
AES					C	2
Entergy	2	0.75	A	4	B+	3.33
FirstEnergy	3	0.75	B+	3.33	B+	3.33
FPL Group	1	0.7	A+	4.33	A-	3.67
PPL	3	0.95	B+	3.33	B	3
Southern	2	0.65	B+	3.33	A-	3.67
KeySpan	2	0.8	B++	3.67	B	3
Ameren	1	0.75	A+	4.33	A-	3.67
Public Service Enterprise Group	3	0.85	B+	3.33	B+	3.33
American Electric Power	3	1.15	B++	3.67	B	3
Progress Energy	2	0.8	B++	3.67	B+	3.33
Duke Energy	3	1.1	B++	3.67	B+	3.33
NiSource	3	0.8	B+	3.33	B	3
TXU	3	1	B	3	B	3
DTE Energy	3	0.7	B+	3.33	B+	3.33
Edison International	4	1.05	C++	2.67	B	3
Consolidated Edsion	1	0.6	A++	4.67	B+	3.33
CINergy	2	0.85	A	4	B+	3.33
Xcel Energy	2	0.8	B++	3.67	B	3
CenterPoint Energy	4	0.6	C++	2.67	B	3

INDUSTRY/Company	Safety	Beta	Fin Str		Stk Rank	
Pinnacle West Capital	1	0.85	A	4	A	4
Peoples Energy	1	0.8	A	4	B	3
Alleghemy Energy	4	1.65	C++	2.67	C	2
Nicor	2	1.05	A	4	B	3
Calpine	5	2.25	C+	2.33	B	3
CMS Energy	4	1.35	C++	2.67	C	2
Dynergy	5	2.5	C	2	C	2
Teco Energy	3	0.9	B	3	B-	2.67
AVERAGE	2.67	1.11	B++	3.69	B+	3.29

CA-T-5
DOCKET NO. 04-0113

DIRECT TESTIMONY AND EXHIBITS

OF

MICHAEL L. BROSCH

ON BEHALF OF
THE DIVISION OF CONSUMER ADVOCACY

SUBJECT: Cost of Service Studies, Rate Increase Distribution, Rate Design & Tariffs.

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DIRECT TESTIMONY OF MICHAEL L. BROSCH

I. INTRODUCTION.

Q. PLEASE STATE YOUR NAME.

A. My name is Michael L. Brosch.

Q. HAVE YOU SUBMITTED TESTIMONY IN THE INSTANT PROCEEDING ON BEHALF OF THE DIVISION OF CONSUMER ADVOCACY, HEREINAFTER REFERRED TO AS CONSUMER ADVOCATE OR CA?

A. I am sponsoring testimony as CA-T-1 in the instant proceeding.

Q. WHAT IS THE PURPOSE OF THE TESTIMONY THAT YOU ARE NOW SPONSORING?

A. As previously stated in CA-T-1. I am also responsible for reviewing the Company's Cost of Service Study (COSS), revenue increase distribution and proposed rates in the instant proceeding. As a result, this testimony will address the results of my review, including recommendations regarding the allocation of the costs among customers classes, the distribution of revenue increases among customer classes and the design of rates that are intended to generate the Consumer Advocate's revenue requirement for the 2005 test year.

II. <u>CLASS COST OF SERVICE</u>

Q. DID THE COMPANY PREPARE ANY COST OF SERVICE STUDIES IN THIS DOCKET?

A. Yes. Ms. Seese (HECO T-22) has prepared embedded and marginal cost of service studies ("COSS") that are summarized in Exhibits HECO-2201 through HECO-2217. The embedded class cost of service study assigns responsibility among each customer class for the test period overall cost of service using actual "embedded" accounting costs, so as to estimate the relative rates of return being earned by serving each class at present and proposed rates. HECO's embedded COSS is prepared on the same basis that revenue requirement is determined, including all of the estimated DSM and other expenses that are the subject of Consumer Advocate ratemaking adjustments.

Q. HOW ARE COST OF SERVICE STUDIES USEFUL IN A RATE CASE DOCKET?

A. COSS information can be used to guide the Commission's decision regarding how much of the overall revenue change in this Docket should be attributed to specific customer classes and rates. Exhibits HECO-2202 through HECO-2205 summarize class revenue requirement and class rate of return data in different formats for this purpose. An additional purpose for conducting <u>embedded</u> cost of service studies is to evaluate "unit costs," which divide allocated costs per unit of demand, energy or by customer as a guide to rate design analysis after revenue distribution decisions have been made (see HECO-2208 and HECO-2210).

The other type of cost study performed by Ms. Seese is an evaluation of "marginal costs," which considers the cost associated with serving an additional or "marginal" customer, unit of energy or unit of demand at differentiated points in time. This type of study does not rely upon actual recorded or projected accounting costs, but instead is based upon more theoretical analyses of the rates of change in energy costs on a time differentiated basis as well as the expected cost of a "next" unit of generating, transmission and distribution capacity. The results of marginal cost studies are useful in considering how to design specific rates and tariffs that are economically efficient, with an awareness of how costs and pricing revenues may interact to influence customer behavior and utility profitability. The Company's embedded cost of service study is the main basis of HECO's present and proposed rates, and the marginal cost study is one of the Company's considerations in the rate design.[1]

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1 CA-IR-371, CA-IR-467.

Q. WHAT DOES THE HECO EMBEDDED COST OF SERVICE STUDY INDICATE REGARDING HOW ANY REVENUE INCREASE IN THIS PROCEEDING SHOULD BE DISTRIBUTED AMONG CUSTOMER CLASSES?

A. The Company's embedded cost of service study ("COSS") results indicating class return levels at present and proposed rates are summarized in Exhibit HECO-2201. At present rate levels and with all of HECO's ratemaking proposals, the overall business is calculated to be earning an overall Rate of Return ("ROR") of only 4.04 percent. Relative to this overall ROR, the Residential Class served on rate "Schedule R" is estimated to be contributing an ROR of only 1.3 percent, or about 32 percent of the overall average ROR of 4.04 percent. Thus, the Company's study would suggest that Schedule R residential revenues should be increased more than the system average percentage increase in order to move closer to the system average "cost of service" for Schedule R. Similarly, the lighting customers on Schedule F are contributing a below average ROR and would require a higher than average percentage revenue increase to move toward indicated cost of service. Conversely, the Company's study shows that all of the commercial rates (Schedules G, H, J, PS, PP and PT) are contributing above-average RORs at present rates, such that they may require a below average percentage revenue increase to move closer to the system average ROR (closer to cost of service). Of course, with the Consumer Advocate's much different revenue requirement and underlying accounting adjustments, the embedded cost of service results are much different in the Consumer Advocate's filing, as discussed more fully herein.

Q. WHAT DOES THE COMPANY'S EMBEDDED COST OF SERVICE REVEAL WITH RESPECT TO RATE DESIGN?

A. HECO-2208 and HECO-2210 summarize the Unit Cost Components using HECO's revenue requirement assumptions and embedded cost allocation methods at proposed rates and at equalized class return levels, respectively. These calculations can be useful to compare rate elements within individual tariffs, such as customer charges, demand charges and energy rates, to the underlying calculated per unit cost to provide service. However, HECO's calculations seriously overstate unit costs because of the excessive revenue requirement proposed by the Company and because of questionable cost allocation methods that are being used. In addition, the "Unit Customer Costs" are particularly overstated because HECO has classified large amounts of proposed DSM costs as Customer Costs, even though the existence of customers does not really drive such costs. Thus, HECO's "Unit Customer Cost" calculations must be discounted in any evaluation of rate design parameters.

Q. ASIDE FROM DIFFERENCES IN OVERALL REVENUE REQUIREMENT, IS THE COMPANY'S EMBEDDED COSS BASED UPON REASONABLE METHODS AND PROCEDURES?

A. In general, yes it is. The Company's study employs a traditional approach in which costs are first functionalized into production, transmission, distribution and customer-related categories. Once functionalized, the costs are classified as demand, energy, or customer driven, and then are allocated among customer classes by applying allocation factors to the functionalized costs.[2] The general procedures employed by Ms. Seese are widely accepted and, with only a few exceptions, reasonable for a utility with HECO's service characteristics. However, I take exception to several specific procedures employed by HECO in the conduct of its cost of service study.

Q. WHAT ARE YOUR CONCERNS REGARDING HECO'S COSS?

A. As will be discussed in further detail in the following sections of my testimony, the Consumer Advocate has concerns with:

- Distribution poles, lines and transformers are improperly classified as "customer" costs.
- HECO's inclusion of DSM costs using a "customer" classification overstates the customer unit costs.

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2 These sequential steps are described at HECO T-22, pages 7 through 14 and depicted at HECO-2212.

- Production O&M expenses other than fuel are classified entirely as fixed or "demand" costs, when a portion of such expenses vary with the level of "energy" generated.
- Energy loss rates are not based upon the correct HECO loss study values.

Q. IS JUDGMENT NECESSARILY INVOLVED IN THE CONDUCT OF ANY EMBEDDED COSS?

A. Yes. Financial and operational data must be analyzed and interpreted by the cost analyst to determine reasonable approaches to the many decisions involved in defining cost classification and allocation methods that will produce meaningful results. Thus, there is no single "correct" embedded cost of service study because of the many judgmental decisions that must be made. The adjustments I propose are intended to improve upon the judgments and estimates employed in the Company's COSS, and are presented as reasonable alternative approaches that should be considered by the Commission.

Q. IS THERE A PRIMARY ISSUE FOR WHICH JUDGMENT IS REQUIRED IN THE CONDUCT OF AN ELECTRIC UTILITY EMBEDDED COST OF SERVICE STUDY?

A. Yes. The single most important judgment in conducting such a study is the selection of the most appropriate production and transmission demand-related cost allocation factor. For this allocation factor, HECO has employed an Average and Excess Demand ("AED") allocation that weights together peak demand data and average demand data, so as to recognize that production and transmission costs are incurred by HECO to meet customer demands during peak periods, as well as throughout the balance of the year (average demands). The AED allocation approach is particularly well suited to HECO, given the Company's relatively high system load factor and non-seasonal demand characteristics.[3] Load factor is the ratio of average demand divided by the product of peak demand times all hours in the period and is an indication of how much of the time demand levels are relatively high in relation to peak demands.

I concur in the use of the AED allocation approach for production and transmission demand cost allocations, but there are certain improvements that should be applied to other elements of HECO's COSS to better determine the costs incurred to provide service to each HECO customer class.

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3 See CA-IR-472(b) for additional information regarding utilization of the AED method.

Q. WHAT ARE THE PROBLEMS WITH HECO'S EMBEDDED COSS THAT SHOULD BE ADJUSTED?

A. There are several specific problems with the Company's study that require adjustment.

First, HECO's embedded COSS classifies a large portion of the costs associated with the network of electric distribution poles, lines and transformers as "customer" driven costs. In addition, the costs of customer service lines and customer meters are classified entirely as "customer" costs. The Consumer Advocate agrees with the classification of service lines and meters as "customer" costs, since these facilities and the related expenses incurred to maintain the facilities are required to connect and serve discrete customers. However, the distribution network of poles, lines and transformers do not vary directly with the number of customers served and should be classified entirely as "demand," rather than partially as "customer" costs, which HECO proposes to do. The HECO studies conducted to determine an estimated fraction of poles, lines and transformers to be classified as "customer" driven are inherently unreliable and the theoretical support for such a "customer" classification is weak, at best.

Second, HECO's study also includes a large amount of Demand Side Management ("DSM") program expenses as "customer" classified costs, with specific assignment of such costs based upon expenditures within each DSM program. However, there are no DSM adjustment revenues in the Company's filing to offset these expenses, because of the proposed roll-in of DSM costs into base rates and exclusion of the related DSM revenues that are being collected under the DSM Adjustment tariff.[4] This mismatch between expenses and revenues contributes to the perception that the Residential class is not earning an adequate return at present rate levels.

Third, HECO's COSS improperly treats all non-fuel production operations and maintenance expenses as "demand" driven. This classification is appropriate for many of the types of costs incurred to operate and maintain generating units, as explained in my prior testimony (CA T-1). Some production O&M costs do, however, vary with KWH output and should therefore be treated as "energy" costs. Ideally, a study would be conducted to determine the mix of demand/energy cost drivers for each O&M account. Thus, HECO should conduct such an analysis in support of its next rate case filing and embedded COSS. I have employed the Federal Energy Regulatory Commission ("FERC") predominance method to evaluate each production O&M account classification, to determine either an energy or demand classification, based upon whether the predominance of costs in the account vary with energy output levels.

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[4] HECO Tariff Revised Sheet No. 68 provides for DSM cost recovery, subject to Commission approval and periodic reconciliation filings.

Finally, a correction is required to properly quantify energy loss percentages used in the embedded COSS, as noted in HECO's response to CA-IR-464.

Q. IN HECO'S EMBEDDED COSS, WHAT PORTION OF ELECTRIC DISTRIBUTION POLES, LINES AND TRANSFORMERS ARE DEEMED TO BE DRIVEN BY THE NUMBER OF CUSTOMERS AND THUS CLASSIFIED AS CUSTOMER COSTS?

A. The HECO embedded COSS assumes that 48 percent of the costs of distribution poles, 42 percent of costs associated with distribution conductors (lines) and 60 percent of distribution transformer costs are caused or influenced by the number of customers being served, with the reciprocal of these percentage values being classified as demand-related.[5]

Q. PLEASE EXPLAIN WHY THE CLASSIFICATION OF ANY PORTION OF ELECTRIC DISTRIBUTION POLES, LINES AND TRANSFORMERS AS "CUSTOMER" RELATED COSTS IS CONTROVERSIAL.

A. The addition of a new customer simply does not cause these costs to be incurred, because these costs are "network" costs for facilities that are designed and constructed to serve the demands of <u>all</u> customers in a given

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5 HECO-WP-2202, page 147.

area. HECO has not shown any positive correlation between the number of customers served and the amount invested in distribution network facilities. The costs that can be clearly shown to vary directly with the connection of a new customer are only those costs that must be added each time a new customer is established – specifically, the costs associated with the service line to the customer and his meter, as well as the related costs to read meters, conduct billing and provide customer contact services.

HECO has improperly attributed distribution network costs, including poles, lines and transformers, to the customer-related classification. While this treatment is consistent with alternatives documented within the NARUC Cost Allocation Manual that is relied upon by HECO, if supported by appropriate cost analyses, this practice has proved to be controversial and has been abandoned by electric utilities in other jurisdictions.[6]

Q. ACCORDING TO MS. SEESE AT PAGE 10, "FOLLOWING THE NARUC COST ALLOCATION MANUAL, THERE ARE TWO METHODS USED TO DETERMINE THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION FACILITIES: (A) THE MINIMUM SIZE METHOD, AND

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[6] For example, Public Service Company of Oklahoma and PSI Energy (in Indiana) include only distribution services and meters as "customer" costs, with the balance of distribution network facilities classified as "demand." See footnote 8.

(B) THE MINIMUM INTERCEPT METHOD." WHAT ARE THESE METHODS?

A. These two analytical methods are theoretical studies intended to segregate a customer versus demand breakdown of distribution network facilities and related costs. The "Minimum Size" method is based upon estimation of the costs that would theoretically be incurred to re-build the entire distribution network using only the smallest sized poles, conductors and line transformers that may be employed by the utility. Then, having estimated costs for this theoretical minimum-sized system, it is assumed that all additional costs in the actual distribution network must have been incurred to "up-size" this minimum-sized system to meet actual demand levels.[7]

The "Minimum Intercept" method cited by Ms. Seese attempts to quantify the theoretical costs involved in re-building the distribution network with zero demand serving capability – with all actual costs above this theoretical "zero-sized" system deemed to be demand-related costs. After describing these concepts at page 11, Ms. Seese claims that "HECO prepares both methods in its cost-of-service study for this proceeding," claiming that, "The results are also shown in HECO-2213."

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[7] HECO attached a partial copy (pages 90-94) of the NARUC Electric Utility Cost Allocation Manual to its response to CA-IR-219 that describes these two approaches in greater detail. Unfortunately, page 95 of the same NARUC manual explains the problems and issues associated with determining a customer component and this page was not copied by HECO.

Q. DID HECO ACTUALLY EMPLOY BOTH METHODS TO QUANTIFY A CUSTOMER COMPONENT FOR CLASSIFICATION OF DISTRIBUTION FACILITIES AND COSTS?

A. No. HECO attempted to prepare calculations under both theoretical approaches. However, the values derived from HECO's application of the minimum intercept method calculations resulted in negative intercept values, which are not meaningful and tend to indicate the theoretical frailty of the logic associated with classifying distribution network costs as customer costs. In its response to CA-IR-218, HECO acknowledged this problem, stating:

> The values from the minimum size system method were adopted and used in the Company's embedded cost of service study, as the minimum intercept method resulted in negative intercept values which are not reasonable since the intercept values represent the plant costs at a no-load situation based on the minimum intercept method's premise. Even when customers are not using kW or kWh, the Company incurs costs connecting customers to the system, and maintaining and operating the distribution plant facilities.

Q. GIVEN THE COMPANY'S INABILITY TO ESTIMATE A CUSTOMER COST COMPONENT FOR DISTRIBUTION NETWORK FACILITIES USING THE MINIMUM INTERCEPT APPROACH, DID HECO RELY SOLELY UPON ITS MINIMUM-SIZED SYSTEM CALCULATIONS TO DETERMINE A CUSTOMER COST COMPONENT?

A. Yes. The "Customer Component" percentages set forth at HECO-WP-2202, page 147 are based solely upon the minimum-sized system theory.

Q. IS THE MINIMUM-SIZED SYSTEM THEORY THAT HECO RELIED UPON A REASONABLE BASIS TO ESTIMATE A CUSTOMER COMPONENT OF DISTRIBUTION NETWORK COSTS?

A. No. This theoretical approach is flawed in the way it double counts cost responsibility. The minimum-sized distribution system that is assumed to be constructed and required to connect customers is actually capable of serving a large percentage of customer demand, particularly for residential customers. However, no credit is given for this demand serving capability when allocation factors are devised and applied to the "demand" component of distribution network costs. Under HECO's proposed COSS, the residential customer class pays for the majority of the deemed customer component of the distribution network which is capable of meeting much of the residential KW demand. Then, residential customers pay again for the demand component based upon their full measured demands. This problem is explained in the NARUC Electric Utility Cost Allocation Manual at page 95:

> The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment; "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.
>
> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the

> minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.
>
> When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

In its response to CA-IR-300, HECO confirmed that its minimum sized distribution transformer is 25kvA and that a 25kvA distribution transformer can serve about 25kW of load. Furthermore, HECO admits that no "demand serving credit" was given in the COSS for this load serving ability, so as to avoid the double counting problem. The minimum sized conductor is sized to serve 106 amps, yet no reduction to customer class demands has been made to account for the load serving ability of conductors treated as customer-related.

Q. IS IT ALWAYS NECESSARY FOR HECO TO CONSTRUCT NEW DISTRIBUTION LINES IN ORDER TO CONNECT AND SERVE CUSTOMERS, AS ASSUMED IN HECO'S CLASSIFICATION OF SUCH COSTS AS A "CUSTOMER" COST?

A. No. Some customers are connected to existing network facilities by merely adding service lines and meters. Adding other customers may require an extension of network facilities, but such extensions are not directly related to the number of customers being served. For example, adding an apartment building or other high-density residential developments may entail minimal new investment in distribution facilities, while adding dozens or hundreds of new customers. The challenges associated with correlating distribution network investment levels for poles, conductors and transformers was confirmed in HECO's responses to CA-IR-299, part c; CA-IR-300, parts c and d; and CA-IR-301, part d, where reference is made by HECO to variables such as density, the amount of existing electrical infrastructure, the proximity of existing facilities and the estimated demand levels of specific customers that all influence distribution network investment levels.

Q. ARE YOU AWARE OF ANY ELECTRIC UTILITIES THAT, UNLIKE HECO, DO NOT CLASSIFY DISTRIBUTION POLES, LINES OR TRANSFORMERS AS "CUSTOMER" COSTS IN THE CONDUCT OF EMBEDDED COST OF SERVICE ANALYSES?

A. Yes. In their most recent rate case proceedings, Public Service Company of Oklahoma and PSI Energy, Inc. classified all distribution poles, lines and line transformers as demand-related costs in the COSS studies filed with the Oklahoma and Indiana regulatory commissions.[8] This treatment of all

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[8] Public Service Company of Oklahoma, Oklahoma Corporation Commission Cause No. PUD 200300076 filed January 23, 2004, Workpaper L-5, page 2, "Classification of Rate Base," PSI Energy Inc., Indiana Utility Regulatory Commission Cause No. 42359 filed March 28, 2003, Petitioner's Exhibit Z, Testimony of Kent K. Freeman, page 24.

distribution network poles, lines and transformers as demand-related avoids the controversy and allocation distortions associated with the HECO "customer" classification approach.

Q. TURNING TO THE DSM CONCERN, PLEASE EXPLAIN WHY HECO'S PROPOSED INCLUSION OF DSM COSTS IN THE ASSERTED REVENUE REQUIREMENT IS DISTORTIVE OF EMBEDDED COSS ALLOCATIONS.

A. The Company has included about $30 million of projected annual DSM-related costs in its asserted revenue requirement, with more than half of such costs assigned to the Residential class.[9] In contrast to this over 50 percent allocation of DSM costs, only approximately one-third of the overall Total Operating Expenses are allocated to the Residential class.[10] Notably, HECO's removal of the DSM revenues in calculating its revenue requirement results in the inclusion of DSM costs with no associated revenues to offset such costs under present rates. This situation contributes significantly to the Company's claimed low earnings at present rate levels. Thus, HECO's presentation of the DSM revenue requirement serves to also depress the Residential customer class' earnings and reported rate of return.

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[9] CA-IR-377, page 4 of 4.

[10] HECO-WP-2202, page 1 of 173 indicates $314 million of "Total Operating Expenses" being attributed to the Residential Schedule R/E customers, out of a Total System amount of $952 million.

Q. ANOTHER PROBLEM YOU IDENTIFIED WITH REGARD TO THE HECO EMBEDDED COSS IS THAT IT IMPROPERLY CLASSIFIES ALL NON-FUEL PRODUCTION OPERATIONS AND MAINTENANCE EXPENSES AS "DEMAND" DRIVEN, WHILE SOME PRODUCTION O&M COSTS ARE VARIABLE SINCE THE COSTS VARY WITH KWH OUTPUT AND SHOULD THUS BE TREATED AS "ENERGY" COSTS. PLEASE EXPLAIN THIS ISSUE.

A. Production O&M expenses include many types of costs that are relatively "fixed" in nature, meaning the costs do not vary directly with the amount of energy that is generated. For example, the workforce consisting of power plant operators draw the same salary and benefits on a given day without regard to how much customer demand is served by the generators at the station. On the other hand, certain other non-fuel production O&M costs are influenced by the level of plant output, where higher output causes additional wear on moving parts or contributes to the amount of consumable materials used for plant operations. The HECO embedded COSS ignores this distinction and simply deems all of the more than $50 million of non-fuel Production O&M expenses as demand related.

Q. HOW SIGNIFICANT IS THIS PROBLEM IN TERMS OF COSS RESULTS?

A. It is impossible to quantify the required adjustment because a special study is required to determine the fixed versus variable nature of costs recorded in the

Production O&M Accounts. HECO has not performed such a study.[11] However, the impact may be substantial, particularly if the testimony of HECO witness T-6 is accurate in attributing HECO's recently higher production O&M expenses to the fact that generating units are being operated more heavily.[12] As a point of reference, under the policy approach used by the Federal Energy Regulatory Commission ("FERC") regarding such matters, nearly half of electric utility non-fuel Production O&M expenses might be re-classified as energy costs. The FERC policy employs a "predominance" method to classify Production O&M in each account whenever special studies have not been prepared by a utility to support more detailed classifications. I applied the FERC method to HECO's actual 2004 Production O&M expenses in Exhibit CA-502 and the result suggests that a 48% energy, 52 % demand classification may be appropriate for the Company. However, I did not apply this estimated re-classification in the Consumer Advocate's presentation of cost of service. Instead, I suggest that HECO be directed by the Commission to refine this element of its COSS in future rate filings.

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11 See CA-IR-220, part f.

12 See for example, HECO T-6 at pages 8 and 30.

Q. WHAT IS THE FINAL REVISION TO HECO'S EMBEDDED COSS THAT YOU REFERENCE?

A. Upon review of the HECO COSS, an inconsistency was noted in the energy loss rates that were employed in the study, relative to the amount of Kalealoa capacity that is available to HECO. In its response to CA-IR-464, HECO stated, "The Company's embedded cost of service study will be updated to use the energy losses based on Kalealoa capacity of 209 megawatts."

Q. HAS THE CONSUMER ADVOCATE RE-CALCULATED THE EMBEDDED COSS BASED UPON THE CONSUMER ADVOCATE ACCOUNTING ADJUSTMENTS AND RECOMMENDED REVENUE REQUIREMENT, EMPLOYING REVISIONS FOR THE CONCERNS YOU RAISE?

A. Yes, restatements and corrections have been made for all issues except the Production O&M issue, for which further studies are required to refine the cost classifications. The Consumer Advocate has re-calculated HECO's embedded cost of service study based upon its pro-forma adjusted rate base and expense amounts. The results of this recalculation are set forth in Exhibits CA-500 and CA-501, which were prepared in the same format as the Company's COSS studies for the sake of comparability.

Q. DID YOU USE THE COMPANY'S ALLOCATION MODEL TO PREPARE YOUR REVISED CLASS COST OF SERVICE STUDY SCHEDULES?

A. Yes. As a matter of efficiency and to aid in comparing the study results, I linked Ms. Seese's spreadsheet model logic into the Consumer Advocate's accounting schedules to prepare my cost of service Exhibits CA-500 and CA-501. Aside from changed test period input amounts for revenues, expense and rate base, the other changes made to the Company's embedded COSS model are:

- Correction of the energy loss input values, in accordance with CA-IR-464.
- Classification of all distribution network poles, lines and transformers as demand-related costs.
- Restatement of the DSM allocation factor applied to customer service expenses to reflect the removal of DSM expenses in the test year, consistent with the removal of the DSM related revenues.

After making these changes, the resulting class rates of return are much closer to equality (i.e., each customer class is contributing the same rate of return on rate base). For example, the indicated Residential Rate of Return with these revisions remains only modestly below the Total System Rate of Return ("ROR"), as shown at the bottom of Exhibit CA-500. Only the Schedule

G General Service and the Schedule PT Large Power customers have an ROR significantly above average, designated as "ROR As % of System ROR."

Q. SHOULD THE COMMISSION RELY SOLELY UPON CLASS COST OF SERVICE ALLOCATIONS TO DETERMINE THE RATE CHANGES IN THIS CASE?

A. No. Cost of service results are estimates based upon methods and judgments of analysts that may vary significantly. In addition, cost of service results can change significantly from one test period to another, due to shifts in load conditions, expense levels or methodology changes. Therefore, cost of service results should be used only as a "guide" in the direction rate changes should occur, while other factors must also be considered by the Commission.

III. <u>REVENUE INCREASE DISTRIBUTION</u>.

Q. DOES HECO ADVOCATE DISTRIBUTING ITS PROPOSED RATE INCREASE OR "RATE SPREAD" AMONG CUSTOMER CLASSES BASED UPON ITS COST OF SERVICE ALLOCATIONS?

A. No. The Company's embedded COSS suggests that Residential Schedule R and Lighting Schedule F customers should receive an above-average rate increase, while all other commercial rate classes should receive a below-average increase. However, HECO has advocated an "across the board" rate increase distribution, which would increase revenues from each rate class on an equal percentage basis. HECO-2201 illustrates the proposed 9.84% revenue increase the Company seeks for each rate schedule.

The rationale for HECO's proposed equal percentage increase across rate classes is explained at page 28 of Mr. Alm's testimony (HECO T-1):

> The requested revenue increase is being allocated as an equal percentage increase to each rate schedule. This departs from past revenue increase allocations, where HECO proposed to allocate the revenue increase to rate schedules, such that the rates moved closer to the cost to serve the rate schedule... After extensive discussion and examination, while the rates should reflect the cost to provide the service, the rate increase impact to customers must also be considered. Based on the $98,614,000 or 9.9% increase, the rate increase to the residential customer would be approximately 15%, based on HECO's criteria that the allocation to the rate schedule should be plus or minus 25% of the system increase, and the class rate of return should be between plus or minus 50% of the system rate of return. Considering the relatively high electric bills for residential customers due to the current fuel prices, an increase of 15% may be difficult for residential customers. Thus, HECO is proposing to allocate the revenue increase to all rate schedules equally to share the burden among all rate-payers. At the same time, if the amount of HECO's final revenue increase approved by the Commission is less than the amount requested in this application, the Commission should consider HECO's past criteria for the revenue increase allocation in making its final revenue allocation.

Because the revenue requirement recommended by the Consumer Advocate is much lower than the $98 million HECO initially requested, the basis for HECO's proposed across the board revenue increase distribution would clearly not apply to the Consumer Advocate's lower revenue requirement.

Q. IS IT APPROPRIATE, AS A MATTER OF REGULATORY POLICY, TO CONDITION THE APPLICATION OF COST OF SERVICE RESULTS UPON POLICY CONSIDERATIONS SUCH AS CUSTOMER IMPACT?

A. Yes. HECO was quite correct in conditioning its use of cost allocation study results upon customer impacts and acceptance. Cost of service allocations are inherently imprecise and dependent upon a multitude of judgments regarding cost causation, as well as imperfect data regarding customer demands and cost classifications. Therefore, cost of service must serve only as a guide and not dictate the distribution of revenue changes among customer classes. It is essential to consider many factors, other than indicated class cost of service results, in determining an appropriate distribution of revenue increases. These other factors include:

- Revenue stability for the utility - rates should not be abruptly changed, creating a risk that customers may modify their demand levels or migrate between rates, producing unexpected revenue impacts.
- Gradualism in customer impacts - customer understanding and acceptance of rate changes is dependent upon avoidance of abrupt monthly bill impacts.
- Administrative practicality – rate structures and the relationship between rates must be rational and simple to apply and understand.

- Public policy priorities such as conservation or low-income assistance – purely cost based rates may fail to meet other desirable public policy objectives.

Q. DOES THE COMPANY'S PROPOSED EQUAL PERCENTAGE RATE INCREASE APPROACH MAKE THE EXISTING DISPARITY IN THE CONTRIBUTION TOWARDS AN EQUAL RATE OF RETURN AMONG RATE CLASSES ANY WORSE?

A. No. Exhibit HECO-2201 indicates that HECO's proposed equal percentage increase actually has the effect of improving the "ROR Index" for most of the various rate schedules, moving each rate class except Large Power Secondary and Large Power Primary ("PS" and "PP") closer to a 100 percent Index.

Q. AT THE MUCH LOWER REVENUE REQUIREMENT RECOMMENDED BY THE CONSUMER ADVOCATE, WHAT DISTRIBUTION OR RATE CHANGES DO YOU RECOMMEND?

A. The following table indicates the sequenced series of rate changes recommended by the Consumer Advocate, to be implemented in order to provide the amount of overall revenue increase ultimately ordered by the Commission. A series of specific rate changes are proposed, totaling $6.8 million, that should be the first rate changes implemented in connection with any revenue increase authorized for HECO by the Commission. Then, all additional new revenue above this amount should be distributed ratably as indicated in the following table:

Sequenced Revenue Increases:		**Revenue $000**
Step 1	Terminate AES Rate Credits	$ 3,187.1
Step 2	Eliminate Power Factor Adjustment Credits	2,928.0
Step 3	Adopt HECO-203 Service Charge Increases	388.2
Step 4	Adopt HECO-203 Field Collection Changes	232.6
Step 5	Adopt HECO-203 Returned Check Charges	44.4
	Subtotal Specific Rate Changes	6,780.3
Step 6	All Remaining Revenues - No Rate Increases to Schedule G and Schedule PT. Equal percentage increases to all other rates.	
Step 7	Continue IRP/DSM Surcharge, subject to reconciliation of costs and revenues and review of programs in the Energy Efficiency Docket.	

Q. PLEASE EXPLAIN THE FIRST ITEM IN YOUR TABLE TO "TERMINATE AES RATE CREDITS."

A. Present rates include a Rate Adjustment tariff (Revised Sheet No. 50.1) to credit customers with $3,187,140 annually in connection with reduced capacity payments under Amendment No. 2 to the AES Hawaii Purchased Power Agreement.[13] In this rate case, all purchased power capacity costs are normalized and included in the overall revenue requirement, eliminating the need for prospective rate adjustments for this past contract amendment. Eliminating the existing AES Rate Adjustment credits to customers will result in a rate increase to HECO in the annual amount of the credit.

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13 See HECO-105, page 5 of 53.

Q. WHAT ARE THE POWER FACTOR CREDITS AND WHY SHOULD THE CREDITS BE ELIMINATED AS PART OF THE RATE CHANGES APPROVED IN THIS DOCKET?

A. As discussed in my revenue requirement testimony (CA T-1) and in Mr. Herz's testimony (CA T-3), HECO is presently crediting or charging commercial customers when they have a measured power factor above or below 85 percent. The Power Factor tariff provisions specify a rate adjustment of 0.10 percent of the customer's monthly energy and demand charge for each 1 percent of average monthly power factor above or below 85 percent.[14] The power factor adjustment provision has been in HECO's tariffs since before the 1930's and the demand/energy adjustment rate was revised from 0.15% to 0.10% effective July 22, 1980, per PUC Decision & Order No. 6275 in Docket No. 3705. HECO believes that the power factor adjustment is economically justified as it provides incentives to customers to install capacitors and reduce the kvar that they require from the system, thereby reducing utility system costs.[15] However, the Company does not have any studies to show whether or not the power factor adjustment in its present form and amount is economically justified.[16]

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[14] See HECO-105, pages 11, 16-17, 19-20 and 22-23.

[15] HECO response to CA-IR-368.

[16] HECO response to CA-IR-532, part a.

Based upon the review and testimony of Consumer Advocate witness Mr. Herz and the absence of cost justification by HECO for the significant power factor credits now being provided to customers, the Consumer Advocate proposes the termination of the credits in this Docket. In addition, HECO should be required in its next rate filing to conduct studies of its incurred costs associated with reactive power issues and propose a cost-based schedule of charges to customers that impose reactive loads and related costs upon the utility.

Q. HOW WAS THE ANNUAL REVENUE AMOUNT ASSOCIATED WITH THE POWER FACTOR CREDITS DETERMINED?

A. The amount is the sum of the net credits shown at pages 54, 110, 124 and 149 of HECO-WP-304, reduced for the correction made in CA Adjustment Schedule C-3 (CA-101) for the estimation error noted in HECO's response to CA-IR-532, part (d). Because the amounts calculated for each rate schedule are <u>net</u> credits, there may be significant power factor positive billings (charges) to some customers that would continue prospectively. The net amount associated with this change is therefore a conservative estimate of the revenue increase associated with eliminating only the credits to customers. A special study may be required of HECO to disaggregate the customer specific credits and charges at present rates, so as to refine the revenue impact associated with this tariff change.

Q. PLEASE EXPLAIN STEPS 3, 4 AND 5 IN YOUR PROPOSED DISTRIBUTION OF THE HECO REVENUE INCREASE.

A. At pages 48 to 51 of HECO T-22, Ms. Seese explains certain proposed changes to certain service-related charges, including the Service Establishment Charge, the Field Collection Charge and the Returned Check Fee. To support these proposed changes, HECO has conducted cost studies that are set forth in HECO-WP-2201. These cost studies are generally supportive of the new proposed price levels for miscellaneous services and HECO's proposals are reasonable in terms of customer impact. Moreover, the proposed increased miscellaneous service charge amounts are consistent with the miscellaneous charges of other utility companies for similar services. For instance, HECO's proposed Service Establishment Charge of $20 during normal business hours and $45 for expedited same day service compare reasonably to charges of The Gas Company at $30 for re-connection service, with a $45 charge for such service other than during normal business hours.[17] Field Collections charges proposed by HECO of $20 are equal in amount to comparable charges imposed by The Gas Company. With respect to returned payment charges, HECO's proposed $16 charge is conservative in relation to The Gas Company's rate of $25.

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[17] The Gas Company, L.L.C. Original Tariff Sheet No. 32, Issue August 8, 2003. The Gas Company also charges a $7.50 service charge to re-open an account that has been closed temporarily at customer request.

At HECO-303 the revenue effect of each of these changes is quantified and these amounts are set forth as steps 3, 4 and 5 of the revenue changes that should be implemented to meet the Commission's ordered overall revenue increase.

Q. FOR THE BALANCE OF ANY REVENUE REQUIREMENT FOUND REASONABLE BY THE COMMISSION IN THIS DOCKET, HOW SHOULD THE REVENUE INCREASE BE DISTRIBUTED AMONG CUSTOMER CLASSES?

A. The remaining revenue increase should be distributed broadly on an equal percentage basis among all customer classes except the Schedule G General Service and Schedule PT Large Power Transmission customer classes that are presently earning above average rates of return under present rates.

Exhibit CA-500 indicates Class Rates of Return on Rate Base as a result of the Consumer Advocate's revenue requirement as well as the adjustments described above to the cost allocation study methodology. At the bottom of the CA-500, one may observe that Rate of Returns among customer classes are all positive in amount and are within close range of the "Total System" ROR except for the Schedule G, Schedule PT and Schedule F classes. Because the General Service Non-Demand (Schedule G) and Large Power Transmission (Schedule PT) classes are earning significantly above-average returns at present rate levels, these classes should not participate in any revenue increases and are not included in the Consumer Advocate's proposed revenue increase distribution.

The following table illustrates this process at three different assumed overall revenue requirement outcomes:

Remaining Revenue Increase:	Assumed Overall Revenue Increase $000	
Assumed Overall Revenue Requirement Amount	$25,000.0	$35,000.0
Less: Specific Rate Changes (Steps 1 through 5)	$(6,780.3)	(6,780.3)
Remaining Sales Rate Increases Required	$18,219.7	$28,219.7
Total Sales Revenues - All Rate Classes	$1,247,222.0	$1,247,222
Less: Schedule G and PT Sales Revenues (Not Increasing)	$96,308	$96,308
Sales Revenues @ Present Rates G, J, PP, PS, F	$1,150,914.0	$1,150,914.0
Percentage Increase Required to Rates G, J, PP, PS, and F	1.58%	2.45%

The "Assumed Overall Revenue Requirement" amounts shown are purely for illustrative purposes and are not intended to correspond to the asserted revenue requirement of any Party in this Docket.

Q. PLEASE EXPLAIN THE CONSUMER ADVOCATE'S TREATMENT OF THE IRP/DSM SURCHARGE TARIFF AND REVENUES IN THIS RATE PROCEEDING.

A. HECO continues to charge customers for Integrated Resource Planning and Demand Side Management ("IRP" and "DSM") costs pursuant to the existing "Integrated Resource Planning Cost Recovery Provision" that is set forth at Revised Sheet Nos. 68 and 68a of the Company's present tariff.[18] According to Mr. Alm's testimony (HECO T-1) at page 3, "Estimated revenues at current

[18] HECO-105, pages 40 and 41.

effective rates for the 2005 test year include revenues of $24,423,000 from the IRP Clause, including $23,744,000 for recovery of DSM Program costs, lost margins and shareholder incentives for DSM programs currently in effect and $678,200 for recovery of a normalized level of incremental IRP planning costs included in the test year estimates (See HECO-RWP-2302)."

In HECO's revenue requirement calculation, none of the IRP Clause revenues have been recognized. In the Company's proposed tariffs, at HECO-106, page 43, the existing IRP Clause tariff is continued, but has no cost amounts entered in the blanks for such input values. At the time the Company's rate case filing was prepared, HECO had apparently intended inclusion of most of its IRP and DSM-related costs in base rates, but with some prospective tariff tracking for any changes in such costs through the IRP Clause tariff.[19] However, in the Commission's Order No. 21698 dated March 16, 2005, the consideration of IRP/DSM and recovery of IRP/DSM costs was separated from the rate case to be taken up in a new Energy Efficiency Docket No. 05-0069.

In the Consumer Advocate's revenue requirement calculations, none of the revenues being collected through the IRP Clause have been considered. With respect to the operating expenses HECO had included in its filing for IRP

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[19] Mr. Hee, HECO T-10 describes a proposed DSM Reconciliation Clause at page 50 as well as continuation of an "IRP adjustment component" of the IRP Clause at page 66. Ms. Seese, HECO T-22 also explains the Company's proposals for IRP Clause continuation at pages 46 through 48.

and DSM activities, Mr. Carver (CA T-2) explains the removal of such costs. It is the Consumer Advocate's understanding that the review of all IRP and DSM-related costs as well as reconciliation of all amounts collected through the IRP Clause will be among the subjects being resolved in the Energy Efficiency Docket. For this reason, the Commission should understand that the revenue requirement and rate changes being recommended by the Consumer Advocate do not recognize or account for the ongoing recovery of revenues through the IRP Clause, nor is any response to the Company's proposals regarding IRP/DSM programs, costs or rate recovery contained within the rate case evidence being offered by the Consumer Advocate at this time.

IV. <u>RATE DESIGN AND TARIFFS</u>.

Q. AT PAGES 17 THROUGH 38 OF HER TESTIMONY, HECO WITNESS MS. SEESE EXPLAINS HECO'S PROPOSED RATE DESIGN APPROACH FOR THE PRIMARY SALES RATES. HAVE YOU REVIEWED THAT TESTIMONY?

A. Yes. Notably, the specific rate design proposed by HECO, as explained in Ms. Seese' testimony were designed to produce a much larger overall revenue increase than is proposed by the Consumer Advocate. Because the precise amount of revenue increase to be awarded in the Commission's Order is not known, I will limit my testimony regarding rate design issues to address the broad rate change concepts being proposed by HECO, rather than formulating specific alternative tariff price amounts. The final rate design required for HECO will need to produce a much smaller revenue increase, reflecting consideration of ratemaking adjustments being proposed by the Consumer Advocate. The smaller overall rate increase provides an opportunity to moderate the customer impacts associated with the large HECO-proposed rate increases that are illustrated in Ms. Seese' Bill Comparison studies set forth at HECO-2226 through HECO-2233.

Q. WHAT GENERAL APPROACH DO YOU PROPOSE REGARDING A RATE DESIGN IMPLEMENTATION PLAN FOR THE REVENUE INCREASES THAT MAY ULTIMATELY BE APPROVED BY THE COMMISSION?

A. I propose that the existing structure of Customer Charges, Minimum Charges, Energy Charges, and Demand Charges within HECO Rate Schedules R, G, J, H, PS, PP, PT and F be retained. Then, after accounting for the Commission approved base fuel energy cost rate as an adjustment to the existing energy rates, all other tariff elements should be adjusted uniformly, in equal percentages, to achieve the revenue levels required for the overall rate schedule.

Q. CAN YOU ILLUSTRATE HOW THIS APPROACH WOULD APPLY TO THE SCHEDULE R RESIDENTIAL SERVICE RATE?

A. Yes. If we assume for illustration purposes that overall revenues from Residential customers are to be increased by 2.0 percent, the following protocol would be followed:

1. Increase the Customer Charge from $7.00 to $7.14.
2. Increase the Non-Fuel Energy Charge from 7.7814 cents/kwh to 7.9370 cents/kwh.
3. Increase the Base Fuel Energy Charge from 3.5140 to the new base fuel cost rate. This change would be largely offset by a revised ECAC rate initially set at zero, reflecting the rolling into base rates of new normalized energy costs.
4. Increase the Minimum Charge from $16.00 to $16.32.

This same basic approach would be applicable to the pricing elements within the other rate schedules.

Q. HECO HAS PROPOSED SIGNIFICANT INCREASES TO THE CUSTOMER CHARGE WITHIN RATE SCHEDULES R, G, J, AND F, AS EXPLAINED IN THE TESTIMONY OF MS. SEESE AT PAGES 18, 21, 24 and 37, WHY DO YOU NOT SUPPORT THESE INCREASES IN YOUR RATE DESIGN PROPOSAL?

A. These changes are not required under the lower revenue requirement being recommended by the Consumer Advocate. In addition, large Customer Charge increases are not supported by the Consumer Advocate's cost of service evidence and contribute to unreasonably abrupt rate increase impacts upon low volume customers.

HECO appears to rely upon its calculation of "unit customer costs" from its embedded COSS to conclude that its proposed large increases in Customer Charge amounts are reasonable.[20] However, HECO's calculations of "unit customer costs" is vastly overstated due to the inclusion of proposed DSM program costs that have been classified as "customer costs," as well as the incorrect classification of part of the cost of distribution network poles, lines and transformers as "customer costs," as explained in my COSS testimony. The Consumer Advocate has quantified "unit customer costs" at much lower levels in Exhibit CA-501, which compare favorably to the existing levels of

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[20] For instance, HECO T-22, stated at page 19, line 4, "The proposed customer charge of $10.00 per month for Single-Phase Service reflects approximately 35% of the full unit customer cost of $29.33 per month for Single-Phase service." The development of this value can be seen at HECO-WP-2202, page 10 of 173 in the row captioned "Total Customer."

Customer Charge and the Minimum Charge provisions within current tariff prices. For example, the existing Residential Customer Charge of $8.00 per month and the Minimum Charge of $16.00 per month are reasonable in relation to estimated "Total Customer" costs of $10.89 per month shown in the "Schedule R/E Residential Service" column of Exhibit CA-501.

Regarding customer impacts, HECO-2226 illustrates the bill impacts associated with HECO's proposed changes to Schedule R for Single-Phase service. HECO's proposed rates produce monthly bill increases to low volume customers as high as 19.31%, due largely to the $3 increase in monthly Customer Charge that is being proposed. Disproportionately large percentage increases to low-usage customers also are proposed for Schedule G (HECO-2227) and Schedule J (HECO-2228), due in part to the proposed large increases in Customer Charges to these classes.

Q. HECO HAS PROPOSED A LARGE NUMBER OF INDIVIDUAL CHANGES TO ITS TARIFF TO CLARIFY EXISTING RATE QUALIFICATION CRITERIA, DEMAND RATCHET PROVISIONS, DISCOUNT TERMS, AND DELIVERY VOLTAGE PROVISIONS. WHICH OF THESE PROVISIONS DOES THE CONSUMER ADVOCATE NOT OPPOSE?

A. The following changes have been reviewed by the Consumer Advocate and are <u>accepted</u> for implementation by HECO:

- Schedule R Apartment House Collection Arrangement – discount and account terms clarification (HECO T-22, page 18);
- Revise Supply Voltage Adjustment percentages and primary service availability for Schedule G (HECO T-22, page 21);
- Limit Qualification for Schedule J service to less than 300 KW per month, subject to grandfathering of existing Schedule J customers exceeding this limit (HECO T-22, page 26);
- Limit Qualification for Schedule PS service to loads in excess of 300 KW per month (HECO T-22, page 29);
- Revise Schedule J demand ratchet simplification to conform to the average ratchet provision within existing Schedules PS, PP, and PT (HECO T-22, page 27);
- Add Network Adjustment to Schedule J in the same form as now exists in Schedule PS (HECO T-22, page 27);
- Increase term of contract provisions in Schedules J, PS, PP, and PT to conform with HECO's Rule 13 regarding customer advances, with cost-based termination charges for early service discontinuation within five years (HECO T-22, pages 28, 30, 33 and 35);
- Secondary metering adjustment revision to Schedules PP and PT, based upon the 2003 system loss analysis (HECO T-22, page 34 and 36); and

- Elimination of the closed Minimum Billing Demand provision on Schedule PT (HECO T-22, page 32).

Q. TO THE EXTENT YOU HAVE NOT SPECIFICALLY ADDRESSED ANY PROPOSED HECO TARIFF REVISIONS THAT ARE SET FORTH IN HECO-106 OR IN MS. SEESE'S TESTIMONY, SHOULD THE COMMISSION ASSUME THAT THE CONSUMER ADVOCATE SUPPORTS ALL OF THE COMPANY'S PROPOSED TARIFF REVISIONS?

A. No. For example, there are numerous pricing revisions proposed within the Company's proposed tariffs associated with load management rates Schedules/Riders U, T, M, and sales to Qualifying Facilities on Schedule Q, based upon the Company's asserted revenue requirement and cost of service allocation results. These proposed new rates are clearly excessive in the context of the Consumer Advocate's revenue requirement recommendation. While not specifically addressed in my rate design testimony, the proposed rates for these Schedules and Riders should be developed to retain existing rate structure relationships, in conformance with the equal percentage adjustment approach described herein.

HECO has also proposed two new Time of Use tariffs; TOU-R and TOU-C to formalize an offering of TOU pricing originally tested as a pilot program for residential customers starting in 2003.[21] The pricing and service terms for these tariff elements are inherently complex and are designed by HECO to be implemented on a phased-in basis. The Consumer Advocate recognizes that HECO's time of use pricing initiative is experimental in nature and does not object to implementing the proposed terms and conditions, with pricing adjusted to conform to the revenue requirement and rate design policies described herein. The Consumer Advocate also reserves the right to monitor and evaluate these TOU pricing initiatives as more information about customer participation becomes available.

Finally, HECO witness Ms. Seese had recommended implementation of a new Schedule G unmetered service provision that the Company now plans to withdraw.[22] Additionally, at pages 64 and 65 of her testimony, Ms. Seese discusses proposed Schedule CHP and proposed Rider EDR that are pending Commission approval in separate Dockets. The proposed Rider EDR has been withdrawn. With regard to HECO's proposed CHP tariffs, the Consumer Advocate has no recommendation in this rate case Docket since the reasonableness of the CHP proposals are to be addressed in Docket No. 03-0366, which has been suspended by the Commission, pending the Commission's determination of the general policy proposals in Docket No. 03-0372.

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[21] See T-22, pages 55 – 64.

[22] See response to CA-IR-365.

Q. ARE THERE ANY EXISTING HECO TARIFFS THAT THE CONSUMER ADVOCATE PROPOSES BE TERMINATED OR CLOSED?

A. Yes. HECO has only one rate schedule that is tied to the specific customer end uses of the energy, which is discussed under the caption "Schedule H – Commercial Cooking and Water Heating Service" at page 28 of Ms. Seese's testimony. Rate Schedule H is available to commercial electric cooking, heating (Including heat pump waterheaters), air conditioning and refrigeration service, where the voltage supplied by the Company is less that 600 volts. Schedule H appears have been a promotional rate, since the customer demand for billing purposes is discounted based upon the connected heating, cooking, and water heating demands. This rate schedule was approved by the PUC in the 1950's and presently serves only about 1,000 customers.[23] One component of the rate that provided for a measured monthly demand value was referred to as Schedule K service and was "closed to new customers after August 31, 1992.

The Consumer Advocate recommends that the remainder of Schedule H be closed to new customers at this time because HECO has demonstrated no need to maintain any end-use rate schedules of this type, Schedule H requires significant on-site inspection efforts by HECO to

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[23] CA-IR-228.

administer[24] and there is no need for any promotional pricing of electricity given the Company's current capacity position relative to growing demand levels.

Q. DID HECO EXPLAIN ANY NEGATIVE IMPACTS THAT COULD ARISE FROM CLOSING SCHEDULE H TO NEW CUSTOMERS PROSPECTIVELY?

A. Yes. In its response to CA-IR-376, the Company noted that a new tenant moving into a service site with an existing Schedule H meter may incur incremental costs for either re-wiring or for higher electric billings with two Schedule G meters. The Company also noted that the definition of new customer would require clarification as to applicability for existing customers moving to another location having an existing "H" meter. The Consumer Advocate would not object to combined metering on Schedule G for tenants moving into a service site with an existing "H" meter and welcomes HECO input on the definitional clarity thought to be needed to properly implement closure of Schedule H prospectively.

Q. DOES THIS COMPLETE YOUR TESTIMONY REGARDING COST OF SERVICE AND RATE DESIGN?

A. Yes.

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[24] In CA-IR-376, HECO estimates that Field Services labor hours expended to administer Schedule H is about 2,600 hours per year, based upon one full time equivalent senior investigator plus associated administrative hours.

CA-T-5
DOCKET NO. 04-0113

EXHIBITS

OF

MICHAEL L. BROSCH

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test-Year 2005
Class Rates Of Return On Rate Base At Present Rates
Consumer Advocate Revenue Requirement

	Schedule R/E Residential Service ($000s)	Schedule G Gen Service Non-Dmd ($000s)	Schedule J Gen Service Demand ($000s)	Schedule H Comm Service ($000s)	Schedule PT Large Power Trans ($000s)	Schedule PP Large Power Pri ($000s)	Schedule PS Large Power Sec ($000s)	Schedule F Street Lighting ($000s)	Total System ($000s)
Revenues									
Sales Revenue	$388,114.2	$72,849.2	$319,005.1	$8,624.1	$23,512.5	$300,916.4	$128,426.4	$6,588.8	$1,248,036.7
Other Operating Revenue	$2,013.6	$228.8	$461.7	$21.7	$9.6	$233.1	$118.6	$18.1	$3,105.2
Total Operating Revenue	$390,127.8	$73,078.0	$319,466.8	$8,645.8	$23,522.1	$301,149.5	$128,545.0	$6,606.9	$1,251,141.9
Expenses:									
Fuel, Purchased Energy	$195,065.2	$34,281.9	$182,520.1	$4,854.8	$15,116.2	$190,447.1	$78,767.5	$3,568.1	$704,620.9
Other Production Costs	$54,739.6	$9,295.9	$42,395.2	$1,199.6	$2,794.1	$37,175.5	$16,281.9	$1,351.6	$165,233.4
Transmission	$2,626.7	$446.1	$2,034.4	$57.6	$134.1	$1,783.9	$781.3	$64.9	$7,929.0
Distribution	$8,191.3	$1,276.3	$5,002.8	$144.8	$4.3	$3,360.7	$1,771.0	$134.0	$19,885.2
Customer Accounts	$9,471.7	$1,168.3	$388.0	$41.3	$0.2	$9.4	$10.5	$17.4	$11,106.8
Uncollectibles	$764.8	$127.1	$185.9	$15.5	$0.0	$24.0	$64.8	$1.2	$1,183.3
Customer Service	$1,655.0	$134.1	$1,064.7	$5.5	$0.6	$26.4	$30.3	$2.1	$2,918.7
Admin And General	$20,361.3	$3,236.6	$13,188.1	$374.1	$741.9	$10,824.0	$4,835.0	$402.9	$53,963.9
Wage Rollback	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Oper & Maint Exp	$292,875.6	$49,966.3	$246,779.2	$6,693.2	$18,791.4	$243,651.0	$102,542.3	$5,542.2	$966,841.2
Depreciation Expense	$29,822.1	$4,473.3	$16,738.1	$498.0	$538.1	$12,098.9	$6,155.3	$458.7	$70,782.5
Taxes Other Than Income	$37,026.5	$6,839.8	$29,650.1	$802.5	$2,144.8	$27,659.7	$11,834.8	$621.9	$116,580.1
Income Taxes	$7,441.4	$3,773.3	$7,333.0	$171.3	$663.7	$4,726.0	$2,063.1	($72.3)	$26,099.5
Amortized ITC	($38.1)	($5.7)	($21.6)	($0.5)	($0.8)	($16.3)	($7.9)	($0.8)	($91.7)
Gain On Sale of Property	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Interest On Cust Deposit	$147.3	$23.0	$92.8	$2.7	$3.6	$71.1	$34.9	$2.6	$378.0
Total Operating Expenses	$367,274.8	$65,070.0	$300,571.6	$8,167.2	$22,140.8	$288,190.4	$122,622.5	$6,552.3	$1,180,589.6
Present Return	$22,853.0	$8,008.0	$18,895.2	$478.6	$1,381.3	$12,959.1	$5,922.5	$54.6	$70,552.3 $70,552.3
Rate Base:									
Gross Plant in Service	$898,987.4	$138,945.9	$547,331.0	$16,050.3	$20,753.7	$417,901.3	$202,935.1	$15,772.0	$2,258,676.7
Depreciation Balance	($400,155.9)	($61,783.3)	($241,675.4)	($7,081.0)	($9,901.3)	($189,616.1)	($89,258.3)	($7,218.3)	($1,006,689.6)
Net Plant In Service	$498,831.5	$77,162.6	$305,655.6	$8,969.3	$10,852.4	$228,285.2	$113,676.8	$8,553.7	$1,251,987.1
Property Held For Future Use	$28.5	$4.8	$21.3	$0.6	$0.0	$18.0	$8.0	$0.9	$82.1
Fuel Inventory	$12,098.1	$2,126.2	$11,320.0	$301.1	$937.5	$11,811.6	$4,885.2	$221.3	$43,701.0
Materials And Supplies	$3,815.1	$605.4	$2,494.7	$72.5	$116.4	$1,992.7	$936.6	$74.4	$10,107.8
Working Cash	$5,805.6	$952.2	$4,436.4	$119.8	$313.0	$4,174.1	$1,774.0	$102.2	$17,677.3
Contributions & Advances	($62,871.1)	($9,542.3)	($36,488.8)	($1,080.4)	($939.2)	($26,099.8)	($13,410.3)	($995.5)	($151,427.4)
Deferred Income Taxes	($52,769.4)	($8,146.4)	($32,025.9)	($939.6)	($1,207.9)	($24,399.3)	($11,868.7)	($921.2)	($132,278.4)
Unamort ITC	($6,288.0)	($970.7)	($3,816.1)	($111.9)	($144.0)	($2,907.4)	($1,414.4)	($109.6)	($15,762.1)
Other Rate Base Items	$17,766.9	$2,736.3	$10,722.9	$316.0	$386.0	$8,114.5	$3,982.6	$306.7	$44,331.9
Total Rate Base	$416,417.2	$64,928.1	$262,320.1	$7,647.4	$10,314.2	$200,989.6	$98,569.8	$7,232.9	$1,068,419.3
Rate of Return (%)	5.49%	12.33%	7.20%	6.26%	13.39%	6.45%	6.01%	0.76%	6.60%
ROR As % Of System ROR	83.11%	186.79%	109.09%	94.78%	202.82%	97.65%	90.99%	11.43%	100.00%

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test-Year 2005
Unit Functionalized Class Revenue Requirements At Equal ROR
Consumer Advocate Revenue Requirement

	Units	Schedule R/E Residential Service	Schedule G Gen Service Non-Dmd	Schedule J Gen Service Demand	Schedule H Comm Service	Schedule PT Large Power Trans	Schedule PP Large Power Pri	Schedule PS Large Power Sec	Schedule F Street Lighting	Total System
Energy:										
Production	¢/kWh	10.057	10.063	10.016	10.06	9.658	9.744	9.986	9.794	9.942
Demand:										
Production	$/kW/Month	$6.06	$9.11	$11.66	$12.20	$15.63	$15.19	$15.18	$18.95	$9.52
Transmission	$/kW/Month	$1.21	$1.87	$2.38	$2.47	$3.27	$3.10	$3.09	$3.76	$1.93
Distribution Primary										
Substations	$/kW/Month	$0.49	$0.74	$0.92	$0.97	$0.00	$1.15	$1.16	$1.58	$0.73
Primary Lines	$/kW/Month	$1.06	$1.62	$2.01	$2.11	$0.00	$2.52	$2.54	$3.44	$1.60
Primary Demand	$/kW/Month	$1.55	$2.36	$2.93	$3.08	$0.00	$3.67	$3.70	$5.02	$2.33
Distribution Secondary										
Secondary Lines	$/kW/Month	$0.65	$0.82	$0.82	$0.95	$0.00	$0.34	$1.07	$0.21	$0.68
Line Transformer	$/kW/Month	$0.60	$0.76	$0.76	$0.88	$0.00	$0.32	$0.99	$0.20	$0.62
Secondary Demand	$/kW/Month	$1.25	$1.58	$1.58	$1.83	$0.00	$0.66	$2.06	$0.41	$1.30
Distribution Demand	$/kW/Month	$2.80	$3.94	$4.51	$4.91	$0.00	$4.33	$5.76	$5.43	$3.63
Total Demand	$/kW/Month	$10.07	$14.92	$18.55	$19.58	$18.90	$22.62	$24.03	$28.14	$15.08
Total Demand & Energy	¢/kWh	17.25	16.98	15.73	16.205	13.014	14.118	15.035	18.251	15.640
Customer:										
Primary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.00
Secondary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Line Transformers	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Services	$/Cust/Month	$3.94	$4.36	$11.38	$4.52	$143.75	$14.01	$8.33	$6.51	$4.16
Meters	$/Cust/Month	$0.77	$1.19	$11.74	$1.50	$264.58	$38.40	$9.25	$2.75	$1.09
Street Lighting	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Accounts	$/Cust/Month	$4.95	$6.15	$7.83	$5.35	$6.25	$7.68	$7.46	$5.79	$5.13
Uncollectibles	$/Cust/Month	$0.28	$0.43	$2.59	$1.38	($25.00)	$16.32	$32.85	$0.49	$0.38
Customer Service	$/Cust/Month	$0.95	$0.77	$23.53	$0.77	$20.83	$23.44	$23.51	$0.74	$1.48
Total Customer		$10.89	$12.90	$57.07	$13.52	$410.41	$99.85	$81.40	$16.30	$12.24
Total	¢/kWh	18.818	18.032	15.956	16.522	13.025	14.127	15.056	18.448	16.186
Unitizing Factors:										
Energy Sales	MWH	2,145,700.0	377,100.0	2,016,900.0	53,400.0	173,308.0	2,163,136.0	872,956.0	40,300.0	7,842,800.0
Sum of Customer Demands	MW (NCD)	15,348.4	1,749.6	6,214.6	167.7	307.8	4,183.2	1,832.8	121.1	29,617.4
Average Annual Customers	Number	257,648.0	25,629.0	6,680.0	1,042.0	4.0	166.0	190.0	406.0	291,765.0

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JOINT ACCOUNTING SCHEDULES

OF THE

CONSUMER ADVOCATE

PREPARED
BY
UTILITECH, INC.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
INDEX TO ACCOUNTING EXHIBITS
AND SUPPORTING SCHEDULES

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Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
CHANGE IN GROSS REVENUE REQUIREMENT
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	HECO PROPOSED		CA PROPOSED	
	(A)	(B)	(C)		(D)	
1	Proposed Rate Base	(a)	$	1,104,784	$	1,068,416
2	Pro Forma Change in Working Cash	(a)		(13,108)		(3,149)
3	Rate Base at Proposed Rates		$	1,091,676	$	1,065,267
4	Rate of Return	(b)		9.11%		7.85%
5	Operating Income Required	Line 3 * Line 4	$	99,452	$	83,623
6	Net Operating Income Available	(c)		44,625		70,556
7	Operating Income Deficiency	Line 5 - Line 6	$	54,827	$	13,068
8	Revenue Conversion Factor	(d)		1.798646		1.796496
9	Revenue Deficiency (Excess)	Line 7 * Line 8	**$**	**98,614**	**$**	**23,476**

Footnotes:

(a) Source: CA Schedule B.
(b) Source: CA Schedule D.
(c) Source: CA Schedule C.
(d) Source: CA Schedule A-1.
(e) Source: HECO-WP-2301, p.1.

LINE NO.	DESCRIPTION	REFERENCE	RATES	COMPANY PROPOSED	CA PROPOSED
	(A)	(B)	(C)	(D)	(E)
1	Gross Electric Sales Revenue			100.0000%	100.0000%
2	Add: Other Operating Revenue	(d)	0.78% / 0.1%	0.780%	0.1000%
3	Total Operating Revenue	Line 1 + 2		100.7800%	100.1000%
4	Less: Franchise Royalty Tax	(a) (b)	2.500%	-2.4968%	-2.5000%
5	Less: Public Service Company Tax	(a)	5.885%	-5.9309%	-5.8909%
6	Less: Public Utility Commission Fees	(a)	0.500%	-0.5039%	-0.5005%
7	Less: Uncollectibles	(a) (c)	0.130%	-0.1300%	0.0000%
8	Net Revenue (before income taxes)	Lines 3..7		91.71845%	91.20862%
9	Less: Effective State Income Tax		6.0150%	-5.51686%	-5.48620%
10	Less: Effective Federal Income Tax		35.0000%	-30.17055%	-30.00285%
11	Net Operating Earnings	Lines 8..10		56.03103%	55.71957%
12	Income to Revenue Multiplier	Line 3 / 11		1.798646	1.796496

Footnotes:

(a) Sources: HECO-WP-1701 & HECO-WP-2301, p.4-6.

(b) In determining "gross receipts" for purposes of annualizing franchise tax, HECO-WP-2301 reduces the pro forma rate increase by related uncollectibles before applying the 2.50% franchise tax rate.

(c) Sources: HECO-905 & HECO-WP-2301, p.4-6. CA factor is "zero" per CA-T-2 recommendation.

(d) Sources: HECO-WP-2301, p.5. The Consumer Advocate includes only late payment fees that vary directly with sales revenue changes, see CA-IR-167

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF JURISDICTIONAL RATE BASE
FOR THE FORECAST 2005 TEST YEAR
(000's)

Exhibit CA-101
Schedule B
Page 1 of 3

LINE NO.	DESCRIPTION	HECO PRO FORMA TEST YEAR	CA ADJUSTMENTS	CA PROPOSED
	(A)	(B)	(C)	(D)
1	Plant In Service	$ 2,289,027	$ (30,354)	$ 2,258,673
2	Less: Accumulated Depreciation	887,080	(5,282)	881,798
3	Less: Regulatory Liability	137,793	(12,903)	124,890
4	Net Plant In Service	1,264,154	(12,169)	1,251,985
5	Property Held for Future Use	599	(517)	82
6	Fuel Inventory	28,742	14,959	43,701
7	Materials & Supplies	9,984	123	10,107
8	Unamortized Net SFAS 109 Regulatory Asset	51,451	(240)	51,212
9	Prepaid Pension Asset	65,899	(65,899)	-
10	Unamortized OPEB Regulatory Asset	9,764	-	9,764
11	Unamortized System Development Costs	369	(369)	-
12	Working Cash (at present rates)	11,820	5,858	17,678
13	Less: Unamortized CIAC	150,713	(783)	149,930
14	Less: Customer Advances	1,357	141	1,498
15	Less: Customer Deposits	6,262	(361)	5,901
16	Less: Accumulated Deferred Income Taxes	153,315	(21,036)	132,279
17	Less: Unamortized ITC	15,762	-	15,762
18	Less: Unamortized Gain on Sales	850	154	1,004
19	Less: OPEB Liability	9,739	-	9,739
20	**Average Net Rate Base**	$ 1,104,784	$ (36,368)	$ 1,068,416
		(a)	(b)	

Footnotes:

(a) Source: HECO-1901 & HECO-1902.
(b) Source: CA Schedule B, p. 3.

Witness: M. Brosch

Exhibit CA-101
Schedule B
Page 2 of 3

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF RATE BASE ADJUSTMENTS
FOR THE FORECAST 2005 TEST YEAR

		ADJUSTMENT NUMBER / SCHEDULE REFERENCE								
LINE NO.	DESCRIPTION	B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Plant In Service	$ (26,449)	$ -	$ (4,959)	$ 1,054	$ -	$ -	$ -	$ -	$ (30,354)
2	Less: Accumlated Depreciation	(5,282)	-	-	-	-	-	-	-	(5,282)
3	Less: Regulatory Liability	(12,903)								(12,903)
4	Net Plant In Service	(8,264)	-	(4,959)	1,054	-	-	-	-	(12,169)
5	Property Held for Future Use	-	-	-	-	(517)	-	-	-	(517)
6	Fuel Inventory	-	-	-	-	-	-	-	14,959	14,959
7	Materials & Supplies	-	123	-	-	-	-	-	-	123
8	Unamortized Net SFAS 109 Regulatory Asset	-	(240)	-	-	-	-	-	-	(240)
9	Prepaid Pension Asset	-	12,892	-	-	-	-	-	-	12,892
10	Unamortized OPEB Regulatory Asset	-	-	-	-	-	-	-	-	-
11	Unamortized System Development Costs	-	-	-	-	-	-	(369)	-	(369)
12	Working Cash	-	-	-	-	-	-	-	-	-
13	Less: Unamortized CIAC	-	(783)	-	-	-	-	-	-	(783)
14	Less: Customer Advances	-	141	-	-	-	-	-	-	141
15	Less: Customer Deposits	-	(361)	-	-	-	-	-	-	(361)
16	Less: Accumulated Deferred Income Taxes	-	7,446	-	-	-	-	-	-	7,446
17	Less: Unamortized ITC	-	-	-	-	-	-	-	-	-
18	Less: Unamortized Gain on Sales	-	154	-	-	-	-	-	-	154
19	Less: OPEB Liability	-	-	-	-	-	-	-	-	-
20	**Average Net Rate Base**	$ (8,264)	$ 6,179	$ (4,959)	$ 1,054	$ (517)	$ -	$ (369)	$ 14,959	$ 8,083

ADJUSTMENTS:

B-1 UPDATE OF NET PLANT ADDITIONS
B-2 OTHER RATE BASE UPDATES
B-3 ELIMINATION OF COMBINED HEAT & POWER PROJECTS
B-4 DISTRIBUTED GENERATION RATE BASE INVESTMENT
B-5 ELIMINATION OF CERTAIN PROPERTY HELD FOR FUTURE USE
B-6 * RESERVED *
B-7 SOFTWARE COSTS
B-8 FUEL INVENTORY

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF RATE BASE ADJUSTMENTS
FOR THE FORECAST 2005 TEST YEAR

Exhibit CA-101
Schedule B

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	B-9	B-10	B-11	B-12	B-13	B-14	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Plant In Service	$ (30,354)	$ -	$ -	$ -	$ -	$ -	$ -	$ (30,354)
2	Less: Accumlated Depreciation	(5,282)	-	-	-	-	-	-	(5,282)
3	Less: Regulatory Liability	(12,903)							(12,903)
4	Net Plant In Service	(12,169)	-	-	-	-	-	-	(12,169)
5	Property Held for Future Use	(517)	-	-	-	-	-	-	(517)
6	Fuel Inventory	14,959	-	-	-	-	-	-	14,959
7	Materials & Supplies	123	-	-	-	-	-	-	123
8	Unamortized Net SFAS 109 Regulatory Asset	(240)	-	-	-	-	-	-	(240)
9	Prepaid Pension Asset	12,892	-	(78,791)	-	-	-	-	(65,899)
10	Unamortized OPEB Regulatory Asset	-	-	-	-	-	-	-	-
11	Unamortized System Development Costs	(369)	-	-	-	-	-	-	(369)
12	Working Cash	-	5,858	-	-	-	-	-	5,858
13	Less: Unamortized CIAC	(783)	-	-	-	-	-	-	(783)
14	Less: Customer Advances	141	-	-	-	-	-	-	141
15	Less: Customer Deposits	(361)	-	-	-	-	-	-	(361)
16	Less: Accumulated Deferred Income Taxes	7,446	-	(28,482)	-	-	-	-	(21,036)
17	Less: Unamortized ITC	-	-	-	-	-	-	-	-
18	Less: Unamortized Gain on Sales	154	-	-	-	-	-	-	154
19	Less: OPEB Liability	-	-	-	-	-	-	-	-
20	**Average Net Rate Base**	$ 8,083	$ 5,858	$ (50,309)	$ -	$ -	$ -	$ -	$ (36,368)

ADJUSTMENTS:

B-9 WORKING CASH ALLOWANCE
B-10 PREPAID PENSION ASSET
B-11 * RESERVED *
B-12 * RESERVED *
B-13 * RESERVED *
B-14 * RESERVED *

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
UPDATE OF NET PLANT ADDITIONS
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	12/31/2004 AMOUNT	12/31/2005 AMOUNT	AVERAGE TEST YEAR AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Projected Net Cost of Plant in Service per HECO	HECO-1901	**$ 1,235,791**	**$ 1,292,517**	**$ 1,264,154**
2	Update to Actual 12/31/2004 Amounts	CA-IR-96, p.2	1,241,908	6,117	< Change @1/1/05
3	2005 Net Plant Additions as filed by HECO	HECO-1801		133,203	
4	Revised Estimated Net Plant Additions - 2005	HECO Letter 6/15/05, Att.5		104,187	
5	Reduction in Projected Net Plant Additions	Line 4 - Line 3		(29,016)	
6	Estimated Plant Additions Adjustment Factor	Line 4 / Line 3		78.2%	Note (a)
7	2005 Estimated Removal Costs - HECO Filed	HECO-1902		5,176	
8	Revised Removal Cost Estimate (Factor)	Line 7 * Line 6		4,048	
9	Reduction in Estimated 2005 Removal Costs	Line 8 - Line 7		(1,128)	
10	2005 Estimated Salvage - HECO Filed	HECO-1902		(179)	
11	Revised Salvage Estimate (Factor)	Line 10 * Line 6		(140)	
12	Increase in Net Plant due to Reduced Salvage	Line 11 - Line 10		39	
13	2005 Estimated Depreciation/Amort. Accrual	HECO-1902		(81,474)	
14	Updated 2005 Depreciation/Amort Accrual Estimate	CA-IR-86		(80,132)	
15	Increase in Net Plant due to Reduced Accruals	Line 14 - Line 13		1,342	
16	Total of Changes to 12/31/2005 Net Plant	Lines 2+5+9+12+15		(22,646)	
17	Revised Net Plant in Service Balances	Line 2; Line 1 + 16	1,241,908	1,269,871	$ 1,255,890
18	**CA ADJUSTMENT TO UPDATE NET PLANT IN SERVICE**	Line 17 - Line 1			**$ (8,264)** Note (b)

Footnotes:

(a) Factor derived on Line 6 is used to estimate changes in Removal Costs and Salvage, assuming ratable changes in these items relative to the level of construction completion activity.

(b) The adjustment to Net Plant is comprised of the following elements:

Original Cost Plant in Service per HECO-1902	2,227,402
Actual Updated Original Cost at 12/31/2004 (CA-IR-96)	2,229,969
Change in Plant in Service at 12/31/2004	2,567
Projected Net Plant Additions in 2005 per HECO-1902	133,203
Revised Net Plant Additions per CA-IR-393	104,187
Change in 2005 Plant Additions	(29,016)
Plant in Service Adjustment at Average	(26,449)
Accumulated Depreciation Adjustment	5,282
Removal Cost Liability	12,903
Total Adjustment to Rate Base	(8,264)

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
OTHER RATE BASE UPDATES
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	12/31/2004 TEST YEAR BEGINNING	12/31/2005 TEST YEAR END	TEST YEAR AVERAGE
	(A)	(B)	(C)	(D)	(E)
1	Materials & Supplies Inventory:				
2	HECO Adjusted M&S Inventory Balances	HECO-1903	$ 10,179	$ 9,789	$ 9,984
3	Adjust to Actual 12/31/2004 Balances	CA-IR-95, p.3	10,425		
4	Revised Balances for Average Test Year	Lines 1 & 2	10,425	9,789	10,107
5	CA ADJUSTMENT TO UPDATE M&S INVENTORY				$ 123
6					
7	Prepaid Pension Asset:				
8	HECO Estimated Pension Asset Balance	HECO-1904	$ 65,899	$ 65,899	$ 65,899
9	Adjust to Actual 12/31/2004 Balance	CA-IR-337, p.5	81,085		
10	Adjust to Revised HECO Projection @ 12/31/2005	DOD-IR-10-4, p.3		76,497	78,791
11	CA ADJUSTMENT TO UPDATE PREPAID PENSION ASSET				$ 12,892
12					
13	Contributions in Aid of Construction:				
14	HECO Estimated Contributions in Aid of Construction	HECO-1908	$ 145,105	$ 156,320	$ 150,713
15	Adjust to Actual 12/31/2004 Balances	CA-IR-95, p.2	144,322		
16	Change at 12/31/2004 (Actual - Forecast)	Line 15 - Line 14	(783)	(783)	
17	Revised Year-end Balance (add change)	Line 14 + Line 16		155,537	
18	Revised Balances for Average Test Year	Lines 15 & 17	144,322	155,537	149,930
19	CA ADJUSTMENT TO UPDATE CONTRIBUTIONS IN AID OF CONSTRUCTION				$ (783)
20					
21	Customer Advances:				
22	HECO Estimated Customer Advances	HECO-1808	$ 1,378	$ 1,335	$ 1,357
23	Adjust to Actual 12/31/2004 Balances	CA-IR-95, p.2	1,519		
24	Change at 12/31/2004 (Actual - Forecast)	Line 22 - Line 23	141	141	
25	Revised Year-end Balance (add change)	Line 22 + Line 24		1,476	
26	Revised Balances for Average Test Year	Lines 23 & 25	1,519	1,476	1,498
27	CA ADJUSTMENT TO UPDATE CUSTOMER ADVANCES				$ 141
28					
29	Customer Deposits:				
30	HECO Estimated Customer Deposits	HECO-902	$ 5,788	$ 6,735	$ 6,262
31	Adjust to Actual 12/31/2004 Balances	CA-IR-95, p.2	5,066		
32	Change at 12/31/2004 (Actual - Forecast)	Line 31 - Line 30	(722)		
33	Revised Balances for Average Test Year	Lines 30 & 31	5,066	6,735	5,901
34	CA ADJUSTMENT TO UPDATE CUSTOMER DEPOSITS				$ (361)
35					
36	Accumulated Deferred Income Taxes				
37	HECO Estimated ADIT Balances	HECO-1705	$ 153,961	$ 152,669	$ 153,315
38	Revised Actual 12/31/2004 & FCST 12/31/05 Balances	DOD-IR-4-4, Rev.	162,314	159,207	160,761
39	Change in ADIT Balances	Line 38 - Line 37	$ 8,353	6,538	
40	CA ADJUSTMENT TO UPDATE ACCUMULATED DEFERRED INCOME TAXES				$ 7,446
41					
42	Unamortized SFAS 109 Regulatory Asset				
43	HECO Estimated SFAS 109 Balances	HECO-1706, p.2	$ 50,078	$ 52,824	$ 51,451
44	Revised Actual 12/31/2004 & FCST 12/31/05 Balances	DOD-IR-10-4, p.3	50,082	52,341	51,212
45	Change in ADIT Balances	Line 44 - Line 43	$ 4	(483)	
46	CA ADJUSTMENT TO UPDATE ACCUMULATED DEFERRED INCOME TAXES				$ (240)
47					
48	Unamortized Gain on Sales				
49	HECO Estimated Gain on Sales Balances	HECO-1320	$ 319	$ 1,380	$ 850
50	Revised Actual 12/31/2004 & FCST 12/31/05 Balances	DOD-IR-10-4, p.3	489	1,518	1,004
51	Change in ADIT Balances	Line 50 - Line 49	$ 170	138	
52	CA ADJUSTMENT TO UPDATE ACCUMULATED DEFERRED INCOME TAXES				$ 154
53					
54	TOTAL ADJUSTMENT TO UPDATE OTHER RATE BASE ELEMENTS				$ 6,179

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
ELIMINATION OF COMBINED HEAT & POWER PROJECTS
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Plant Investment in Combined Heat & Power Projects:		
2	Estimated 2004 Investment - Beginning of Test Year	HECO-701	$ 370
3	Estimated Investment - End of Test Year 2005	"	9,547
4	Average Test Year Investment in CHP within HECO Rate Base	Avg. Lines 2 & 3	4,959
5	**CA ADJUSTMENT TO REMOVE CHP PLANT INVESTMENT**		**$ (4,959)**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
DISTRIBUTED GENERATION RATE BASE INVESTMENT
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1 2	Distributed Generation Capitalized Costs - engineering, site work transformers, fuel tanks and other equipment	(a)	$ 2,108
3	Distributed Generation Plant Costs at December 31, 2004	(a)	-
4	**CA ADJUSTMENT TO INCLUDE DISTRIBUTED GENERATION IN AVERAGE RATE BASE**		**$ 1,054**

Footnotes:

(a) Detailed Estimate of DG Capital Expenditures provided by HECO in Attachment 1A to May 5, 2005 Test Year Rate Case Updates Letter at page 7.

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
ELIMINATION OF CERTAIN PROPERTY HELD FOR FUTURE USE
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HECO Investment in Kalealoa-Barbers Point	HECO-1806	$ 517
2	Pipeline acquired 1991	page 2	
3	**CA ADJUSTMENT TO ELIMINATE PHFFU IN EXCESS OF 10 YEARS**		**$ (517)**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
* RESERVED *
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1			
2	*INTENTIONALLY LEFT BLANK*		
3			
4			

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SOFTWARE COSTS
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule B-7
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Unamortized System Development Costs - HRS:		
2	HECO 12/31/04 Balance	(a)	$ -
3	HECO 12/31/05 Balance	(a)	737
4	Average 2005 Balance		$ 369
5	**CA ADJUSTMENT TO ELIMINATE AVG BAL OF UNAMORTIZED HRS SYSTEM**		**$ (369)**
6	**DEVELOPMENT COSTS FROM RATE BASE**		

Footnotes:

(a) Source: HECO-1906 & HECO responses to CA-IR-352 & CA-IR-661.

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
FUEL INVENTORY
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule B-8
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT	
	(A)	(B)	(C)	
1	Fuel Inventory per HECO Filing	HECO-408	$	28,742
2	Fuel Inventory per Consumer Advocate T-3	CA-308		43,701
3	**CA ADJUSTMENT TO RESTATE FUEL INVENTORY**	Line 2 - Line 1	**$**	**14,959**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
WORKING CASH ALLOWANCE
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	Revenue Collection Lag (Days) HECO-904	Payment Lag (Days)	Net Collection Lag (Days) (B) - (C)	Consumer Advocate's Annual Amount (Note (a))	Average Daily Amount - Present (E) / 365	Working Cash Required (Provided) under Present Rates (D) x (F)	Average Daily Amount - Proposed (E) / 365	Working Cash Required (Provided) under Proposed Rates (D) x (H)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	ITEMS REQUIRING WORKING CASH:								
2	Fuel Purchases	37	16	21	$ 444,573	$ 1,218	$ 25,578	$ 1,218	$ 25,578
3	O&M Labor	37	11	26	78,106	214	5,564	214	5,564
4	O&M Nonlabor	37	31	6	309,307	847	5,085	847	5,085
5	ITEMS PROVIDING WORKING CASH:								
6	Purchased Power	37	39	(2)	368,341	1,009	(2,018)	1,009	(2,018)
7	Revenue Taxes - Present Rates	37	90	(53)	88,463	242	(12,845)		
8	Revenue Taxes - Proposed Rates	37	90	(53)	90,587			248	(13,154)
9	Income Taxes - Present Rates	37	162	(125)	10,759	29	(3,685)		
10	Income Taxes - Proposed Rates	37	162	(125)	19,246			53	(6,591)
11	CONSUMER ADVOCATE WORKING CASH ALLOWANCE						17,678		14,463
12	CONSUMER ADVOCATE CHANGE IN WORKING CASH								(3,215)
13	HECO PROPOSED WORKING CASH / CHANGE IN WORKING CASH AMOUNTS (HECO-1907)						11,820		(13,108)
14	**CONSUMER ADVOCATE ADJUSTMENT TO WORKING CASH AND CHANGE IN WORKING CASH**						$ 5,858		$ 9,893

Footnotes:

(a) Derivation of Annual Expense Amounts for Column E:

	Amounts per HECO-1907	CA Schedule C Adjustments	Amounts per Consumer Advocate
Fuel Expense	$287,634	$156,939	444,573
O&M Labor	78,106	-2,251	75,855
O&M Non-Labor	115,332	193,975	309,307
Purchased Power	298,564	69,777	368,341

		Effect of CA Rate Increase	$23,968	
		Tax Rate %	Added Tax	Amount per CA
Revenue Tax	88,463	8.862%	2,124	90,587
Income Tax	10,759	35.411%	8,487	19,246

($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HECO Update Pension Asset Included in Rate Base	(a)	$ 78,791
2	Less: Accumulated Deferred Income Tax Reserve	(b)	(28,482)
3	Net Pension Asset in HECO's Updated Rate Base		$ 50,309
4	**CA ADJUSTMENT TO ELIMINATE NET PENSION**		**$ (50,309)**
5	**ASSET FROM RATE BASE**		

Footnotes:

(a) Source: CA Schedule B-2 & HECO response to CA-IR-337.

(b) Source: $28,515,000 per HECO response to CA-IR-356, revised 5/26/05. Further modified by HECO's revised response to DOD/HECO-IR-4-4.

	12/31/04 Actual	12/31/05 FCST
State ADIT	$ 4,544	$ 4,268
Federal ADIT	24,831	23,322
Total	$ 29,375	$ 27,590

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
* RESERVED *
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1			
2	*INTENTIONALLY LEFT BLANK*		
3			
4			

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF OPERATING INCOME
FOR THE FORECAST 2005 TEST YEAR
(000's)

LINE NO.	DESCRIPTION (A)	HECO PRO FORMA (B)	CA ADJUSTMENTS (C)	CA PROPOSED (D)
1	**Operating Revenue**	$ 997,107	$ 254,035	$ 1,251,142
2	**Operating Expenses**			
3	Fuel	$ 292,704	$ 156,939	$ 449,643
4	Purchased Power	298,564	69,777	368,341
5	Production	55,041	(3,172)	51,869
6	Transmission	8,087	(158)	7,929
7	Distribution	20,132	(247)	19,885
8	Customer Accounts	11,436	(329)	11,107
9	Allowance for Uncollectible Accounts	1,292	(109)	1,183
10	Customer Service	33,458	(30,539)	2,919
11	Administrative & General	54,443	(481)	53,962
12	Total O&M Expense	775,157	191,681	966,838
13	Depreciation and Amortization	72,056	(1,366)	70,690
14	Taxes Other Than Income Taxes	94,233	22,348	116,581
15	Interest on Customer Deposits	378	-	378
16	Operating Expenses Before Income Taxes	$ 941,824	$ 212,663	$ 1,154,487
17	Operating Income Before Income Taxes	55,283	41,372	96,655
18	Income Taxes	10,658	15,441	26,099
19	**Net Operating Income**	$ 44,625	$ 25,931	$ 70,556
		(a)	(b)	

Footnotes:

(a) Source: HECO-2301.

(b) Source: CA Schedule C, page 5.

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2005 TEST YEAR
(000's)

		ADJUSTMENT NUMBER / SCHEDULE REFERENCE									
LINE NO.	DESCRIPTION	C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Operating Revenue**	$ 1,662	$ 135	$ 715	$ 251,628	$ 30	$ (134)	$ -	$ -	$ -	$ 254,035
2	**Operating Expenses**										
3	Fuel	$ -	$ -	$ -	$ 156,939	$ -	$ -	$ -	$ -	$ -	$ 156,939
4	Purchased Power	-	-	-	69,777	-	-	-	-	-	69,777
5	Production	-	-	-	-	-	(220)	394	(1,769)	(1,394)	(2,989)
6	Transmission	-	-	-	-	-	-	-	-	-	-
7	Distribution	-	-	-	-	-	-	-	-	-	-
8	Customer Accounts	-	-	-	-	-	-	-	-	-	-
9	Allowance for Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
10	Customer Service	-	-	-	-	-	-	-	-	-	-
11	Administrative & General	-	-	-	-	-	-	-	-	-	-
12	Total O&M Expense	-	-	-	226,716	-	(220)	394	(1,769)	(1,394)	223,727
13	Depreciation and Amortization	-	-	-	-	-	(4)	-	-	-	(4)
14	Taxes Other than Income Taxes	148	12	63	22,357	-	(12)	-	-	-	22,568
15	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
16	Operating Expenses Before Income Taxes	148	12	63	249,073	-	(236)	394	(1,769)	(1,394)	246,291
17	Operating Income Before Income Taxes	1,514	123	651	2,555	30	102	(394)	1,769	1,394	7,743
18	Income Taxes	589	48	253	994	12	40	(153)	688	542	3,013
19	**Net Operating Income**	$ 925	$ 75	$ 398	$ 1,561	$ 18	$ 62	$ (241)	$ 1,081	$ 852	$ 4,730

ADJUSTMENTS:
C-1 SALES VOLUME UPDATE ADJUSTMENT
C-2 RATE RIDER DISCOUNT ADJUSTMENT
C-3 SCHEDULE PP POWER FACTOR CORRECTION
C-4 FUEL EXPENSE & ENERGY COST ADJUSTMENT SYNCHRONIZATION
C-5 GAIN ON SALE AMORTIZATION
C-6 ELIMINATION OF COMBINED HEAT & POWER PROJECTS
C-7 INCREASE EXPENSE FOR DISTRIBUTED GENERATION
C-8 PRODUCTION OPERATIONS EXPENSE
C-9 PRODUCTION MAINTENANCE EXPENSE

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2005 TEST YEAR
(000's)

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE								SUBTOTAL
			C-10	C-11	C-12	C-13	C-14	C-15	C-16	C-17	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Operating Revenue**	$ 254,035	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 254,035
2	**Operating Expenses**										
3	Fuel	$ 156,939	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,939
4	Purchased Power	69,777	-	-	-	-	-	-	-	-	69,777
5	Production	(2,989)	-	-	-	-	(68)	-	-	-	(3,057)
6	Transmission	-	-	-	-	-	(9)	-	-	-	(9)
7	Distribution	-	-	-	-	-	(26)	-	-	-	(26)
8	Customer Accounts	-	-	-	-	-	-	-	-	-	-
9	Allowance for Uncollectible Accounts	-	-	-	-	(109)	-	-	-	-	(109)
10	Customer Service	-	-	-	-	-	-	-	-	(30,253)	(30,253)
11	Administrative & General	-	-	-	-	-	(643)	601	32	(618)	(628)
12	Total O&M Expense	223,727	-	-	-	(109)	(746)	601	32	(30,871)	192,634
13	Depreciation and Amortization	(4)	(1,394)	32	-	-	-	-	-	-	(1,366)
14	Taxes Other than Income Taxes	22,568	-	-	-	-	-	-	-	-	22,568
15	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
16	Operating Expenses Before Income Taxes	246,291	(1,394)	32	-	(109)	(746)	601	32	(30,871)	213,836
17	Operating Income Before Income Taxes	7,743	1,394	(32)	-	109	746	(601)	(32)	30,871	40,198
18	Income Taxes	3,013	542	(12)	-	42	290	(234)	(12)	12,012	15,641
19	**Net Operating Income**	$ 4,730	$ 852	$ (20)	$ -	$ 66	$ 456	$ (367)	$ (20)	$ 18,859	$ 24,557

ADJUSTMENTS:
- **C-10** DEPRECIATION EXPENSE ADJUSTMENT
- **C-11** AMORTIZATION OF CIAC
- **C-12** * RESERVED *
- **C-13** UNCOLLECTIBLE EXPENSE
- **C-14** SOFTWARE COSTS
- **C-15** LEASE AGREEMENT REVISIONS
- **C-16** ALLOCATION OF HEI CHARGES TO HECO
- **C-17** REMOVE DSM PROGRAM COSTS

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2005 TEST YEAR
(000's)

Exhibit CA-101
Schedule C
Page 4 of 5

LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	ADJUSTMENT NUMBER / SCHEDULE REFERENCE C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	SUBTOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Operating Revenue**	$ 254,035	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 254,035
2	**Operating Expenses**										
3	Fuel	$ 156,939	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,939
4	Purchased Power	69,777	-	-	-	-	-	-	-	-	69,777
5	Production	(3,057)	-	-	(96)	(19)	-	-	-	-	(3,172)
6	Transmission	(9)	-	-	(14)	(135)	-	-	-	-	(158)
7	Distribution	(26)	-	-	(35)	(186)	-	-	-	-	(247)
8	Customer Accounts	-	-	-	(25)	(204)	-	-	(100)	-	(329)
9	Allowance for Uncollectible Accounts	(109)	-	-	-	-	-	-	-	-	(109)
10	Customer Service	(30,253)	-	-	(14)	(272)	-	-	-	-	(30,539)
11	Administrative & General	(628)	(9)	505	(61)	(784)	212	-	(97)	381	(481)
12	Total O&M Expense	192,634	(9)	505	(246)	(1,599)	212	-	(197)	381	191,681
13	Depreciation and Amortization	(1,366)	-	-	-	-	-	-	-	-	(1,366)
14	Taxes Other than Income Taxes	22,568	-	-	(19)	-	-	-	-	-	22,550
15	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-
16	Operating Expenses Before Income Taxes	213,836	(9)	505	(264)	(1,599)	212	-	(197)	381	212,865
17	Operating Income Before Income Taxes	40,198	9	(505)	264	1,599	(212)	-	197	(381)	41,170
18	Income Taxes	15,641	3	(196)	103	622	(82)	(592)	76	(148)	15,427
19	**Net Operating Income**	$ 24,557	$ 5	$ (308)	$ 162	$ 977	$ (130)	$ 592	$ 120	$ (233)	$ 25,743

C-18 RATE CASE EXPENSE
C-19 CUSTOMER SERVICE REORGANIZATION
C-20 STANDARD LABOR RATES & OVERTIME PAY
C-21 AVERAGE EMPLOYEE LEVELS
C-22 EMPLOYEE BENEFITS
C-23 AMORTIZATION OF DEBT-RELATED COSTS
C-24 RESEARCH & DEVELOPMENT
C-25 KPMG AUDIT / SOX CHARGES

Witness: M. Brosch

Exhibit CA-101
Schedule C
Page 5 of 5

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SUMMARY OF NOI ADJUSTMENTS
FOR THE FORECAST 2005 TEST YEAR
(000's)

			ADJUSTMENT NUMBER / SCHEDULE REFERENCE								
LINE NO.	DESCRIPTION	PRIOR PAGE SUBTOTAL	C-26	C-27	C-28	C-29	C-30	C-31	C-32	C-33	TOTAL
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Operating Revenue**	$ 254,035	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 254,035
2	**Operating Expenses**										
3	Fuel	$ 156,939	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,939
4	Purchased Power	69,777	-	-	-	-	-	-	-	-	69,777
5	Production	(3,172)	-	-	-	-	-	-	-	-	(3,172)
6	Transmission	(158)	-	-	-	-	-	-	-	-	(158)
7	Distribution	(247)	-	-	-	-	-	-	-	-	(247)
8	Customer Accounts	(329)	-	-	-	-	-	-	-	-	(329)
9	Allowance for Uncollectible Accounts	(109)	-	-	-	-	-	-	-	-	(109)
10	Customer Service	(30,539)	-	-	-	-	-	-	-	-	(30,539)
11	Administrative & General	(481)	-	-	-	-	-	-	-	-	(481)
12	Total O&M Expense	191,681	-	-	-	-	-	-	-	-	191,681
13	Depreciation and Amortization	(1,366)	-	-							(1,366)
14	Taxes Other than Income Taxes	22,550	(202)	-							22,348
15	Interest on Customer Deposits	-	-	-							-
16	Operating Expenses Before Income Taxes	212,865	(202)	-							212,663
17	Operating Income Before Income Taxes	41,170	202	-							41,372
18	Income Taxes	15,427	79	(65)							15,441
19	**Net Operating Income**	$ 25,743	$ 123	$ 65	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,931

ADJUSTMENTS:
C-26 TAXES OTHER -- SUTA REDUCTION
C-27 INTEREST EXPENSE DEDUCTION
C-28 * RESERVED *
C-29 * RESERVED *
C-30 * RESERVED *
C-31 * RESERVED *
C-32 * RESERVED *
C-33 * RESERVED *

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SALES VOLUME UPDATE ADJUSTMENT
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	RATE SCHEDULE	HECO-201 PREFILED GWH SALES	HECO REVISED (a) GWH SALES	DIFFERENCE SALES ADJUSTMENT	AVERAGE REVENUE (b) PER GWH $000	TEST YEAR ADJUSTMENT $000
	(A)	(B)	(C)	(D)	(E)	(F)
1	Residential R	2,145.7	2,154.4	8.7	$ 138.8	$ 1,208
2	Commercial G	377.1	377.5	0.4	$ 137.4	55
3	Commercial J	2,016.9	2,013.0	(3.9)	$ 125.5	(490)
4	Commercial H	53.4	53.4	-	$ 121.2	-
5	Large Commercial P	3,209.4	3,217.4	8.0	$ 111.1	889
6	Lighting F	40.3	40.3	-	$ 131.5	-
7	Total Sales Volume Change per HECO	7,842.8	7,856.0	13.2		
8	**CA ADJUSTMENT FOR HECO SALES VOLUME UPDATE**					**$ 1,662**

		Tax Rate	Revenue Change	
9	Additional Revenue Taxes on Incremental Revenues			
10	Franchise Royalty Tax	2.500%	$1,662	$ 42
11	Public Service Company Tax	5.885%	$1,662	98
12	Public Utility Commission Fees	0.500%	$1,662	8
13	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX ON INCREMENTAL REVENUES**			**$ 148**

Footnotes:

(a) HECO Revised GWh Sales per May 5 HECO Update Letter, Attachment 1, page 2.
These revised GWh volumes are used by CA witness Herz (CA T-3) to calculate fuel/ purchased power expenses.

(b) Average Revenue per GWh is Derived from HECO-WP-304 Revenue Calculations, including energy, demand and ERAC revenues at HECO proposed fuel cost recovery levels, summarized as follows:

		Revenue Excluding Customer Charges			
Rate Schedule	Sales MWH	Energy, ECAC & Demand Rev $000	Average Cents/KWH	Average $ / GWH	Average of PS and PP
Schedule R	2,145,700	$ 297,853	13.881400	$ 138,814	
Schedule G	377,100	51,825	13.742986	137,430	
Schedule J	2,016,900	253,161	12.552001	125,520	
Schedule H	53,400	6,473	12.121723	121,217	
Schedule PS	872,956	99,285	11.373460	113,735	
Schedule PP	2,163,136	234,560	10.843502	108,435	$ 111,085
Schedule PT	173,308	18,265	10.539040	105,390	
Schedule F	40,300	5,301	13.152854	131,529	
Total Sales	7,842,800				

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
RATE RIDER DISCOUNT ADJUSTMENT
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR REVENUE AMOUNT
	(A)	(B)	(C)
1	Elimination of HECO Economic Development Rate Discounts	CA-IR-235	$ 7
2	Elimination of Revenue Discounts for Assumed Rider Customers:		
3	Schedule J Mb J11	HECO-WP-304, p.66	9
4	Mb J12	HECO-WP-304, p.67	9
5	Mb J13	HECO-WP-304, p.68	9
6	Schedule PS IPS1	HECO-WP-304, p.116	26
7	Schedule PP IPP3	HECO-WP-304, p.137	64
8	IPP4	HECO-WP-304, p.138	30
9	Total Adjustment to Remove Revenue Adjustments for Assumed		
10	New Rider Customers (Other than CHP and EDR)	Sum Lines 3..8	148
11	Less: Allowance for One New Rider M Customer on Schedule J	DOD/HECO-IR-11-1	(20)
12	Net CA Adjustment to Eliminate Potential Rider Revenue Effects	Line 10 - Line 11	128
13	**CA ADJUSTMENT TO NORMALIZE RIDER DISCOUNTS**	Line 1 + Line 12	**$ 135**

LINE NO.		Tax Rate	Revenue Change	
14	Additional Revenue Taxes			
15	Franchise Royalty Tax	2.500%	$135	$ 3
16	Public Service Company Tax	5.885%	$135	8
17	Public Utility Commission Fees	0.500%	$135	1
18	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX RIDER REVENUES**			**$ 12**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SCHEDULE PP POWER FACTOR CORRECTION
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule C-3
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT
	(A)	(B)		(C)
1	HECO Calculated Power Factor % - Schedule PP	HECO-WP-304, p124		$ 99
2	Base Power Factor %	"		85
3	Difference	"		(14)
4	Adjustment for Each 1% Difference	"		0.001
5	Power Factor Adjustment Rate	"		(0.014)
6	Total Schedule PP Demand/Energy Revenues	"		178,621
7	HECO Schedule PP Power Factor Amount	"		(2,501)
8	Corrected Actual Power Factor %	CA-IR-532		95
9	Base Power Factor %	Line 2		85
10	Difference	Line 9 - Line 8		(10)
11	Adjustment for Each 1% Difference	Line 4		0.001
12	Power Factor Adjustment Rate	Line 10 * Line 11		(0.010)
13	Total Schedule PP Demand/Energy Revenues	Line 6		178,621
14	Corrected Schedule PP Power Factor Amount	Line 12 * Line 13		(1,786)
15	**CA ADJUSTMENT TO CORRECT POWER FACTOR ADJUSTMENT FOR SCHEDULE PP**			**$ 715**
		Tax Rate	Revenue Change	Additional Revenue Tax
16	Additional Revenue Taxes			
17	Franchise Royalty Tax	2.500%	$715	$ 18
18	Public Service Company Tax	5.885%	$715	42
19	Public Utility Commission Fees	0.500%	$715	4
20	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX RIDER REVENUES**			**$ 63**

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
FUEL EXPENSE & ENERGY COST ADJUSTMENT SYNCHRONIZATION
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	HECO PROPOSED AMOUNT	CONSUMER ADVOCATE AMOUNT	DIFFERENCE ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)
1	Fuel Oil Expense - Production Simulation	HECO-401 / CA-304	$ 287,531	$ 444,934	$ 157,403
2	Fuel Related Expense	HECO-405 / CA-305	5,173	4,709	(464)
3	**CA ADJUSTMENT TO FUEL EXPENSE**	Line 1 + 2	292,704	449,643	**$ 156,939**
4	Purchased Power - Energy Payments	HECO-501 / CA-312	189,943	260,048	70,105
5	Purchased Power - Capacity Payments	HECO-501 / CA-313	108,621	108,293	**(328)**
6	**CA ADJUSTMENT TO PURCHASED POWER EXPENSE**	Line 4 + 5	298,564	368,341	**$ 69,777**
7	**Energy Cost Adjustment Rate / Present Rates (cents/kwh)**	HECO-1032/CA-314	2.586	5.789	3.203
			Rev. HECO GWH CA Sched. C-1	Times ECAC Difference	ECAC Revenue Increase
8	Test Year Proposed Sales - Gigawatthours				
9	Residential R		2,154.4	3.203	$ 69,005
10	Commercial G		377.5	3.203	12,091
11	Commercial J		2,013.0	3.203	64,476
12	Commercial H		53.4	3.203	1,710
13	Large Commercial P		3,217.4	3.203	103,053
14	Lighting F		40.3	3.203	1,291
15	Total Sales Volume		7,856.0		
16	**CA ADJUSTMENT TO ECAC GROSS REVENUES AT CA FUEL/ENERGY COSTS**				**$ 251,628**
			Tax Rate	Times ECAC Revenue Change	
17	Additional Revenue Taxes on Incremental ECAC Revenues				
18	Franchise Royalty Tax		2.500%	$251,628	$ 6,291
19	Public Service Company Tax		5.885%	$251,628	14,808
20	Public Utility Commission Fees		0.500%	$251,628	1,258
21	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX ON ECAC REVENUES**				**$ 22,357**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
GAIN ON SALE AMORTIZATION
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Updated Gain on Sale - Iolani Court Plaza	CA-IR-332, 372	$ 67
2	Less: Amount Included in HECO Filing - Iolani	HECO-1320	32
3	Adjustment to Update Iolani Court Plaza Gain on Sale	Line 1 - Line 2	35
4	Normalization of Lilipuna Expiring Gain Amortization	HECO-1320, CA-IR-332, p2	(5)
5	**CA ADJUSTMENT TO NORMALIZE AND UPDATE GAIN ON SALE AMORTIZATION**		**$ 30**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
ELIMINATION OF COMBINED HEAT & POWER PROJECTS
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule C-6
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT
	(A)	(B)		(C)
1	Elimination of CHP Test Year Revenue Adjustments (Note a)	HECO-WP-304		
2	CHP J1	Page 55		$ (32)
3	CHP PS1	Page 111		(9)
4	CHP PS2	"		(26)
5	CHP PS3	"		(14)
6	CHP PP1	Page 126		(25)
7	CHP PP2	"		(19)
8	CHP PP3	"		(9)
9	Total Adjustment Required to Eliminate CHP Related Revenues	Sum Lines 2..8		(134)
10	Elimination of CHP Systems Projected O&M Expenses			
11	CHP Operations Expenses	HECO-616, HECO-701		(63)
12	CHP Maintenance Expenses	"		(157)
13	Total Adjustment Required for CHP O&M Elimination			(220)
14	Elimination of CHP Systems Depreciation Expense	HECO T-7, page 20		(4)
15	**CA ADJUSTMENT TO PRETAX OPERATING INCOME ASSOCIATED WITH CHP ELIMINATION**			**$ 90**
		Tax Rate	Revenue Change	Additional Revenue Tax
16	Change in Revenue Taxes			
17	Franchise Royalty Tax	2.500%	($134)	$ (3)
18	Public Service Company Tax	5.885%	($134)	(8)
19	Public Utility Commission Fees	0.500%	($134)	(1)
20	**CA ADJUSTMENT TO TAXES OTHER - REVENUE TAX CHP REVENUES**			**$ (12)**

Footnotes:

(a) Revenue impacts include CHP Discounts, Facilities Fees and Thermal Fees, as set forth for all projects in HECO-701, page 1, lines 15-18. Lines 2 through 8 identify these amounts by CHP project.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
INCREASE EXPENSE FOR DISTRIBUTED GENERATION
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT	
	(A)	(B)	(C)	
1	HECO Estimated Expenses for Distributed Generation Installations:			
	Rental Expense			
2	DG Unit Rentals - Rental Rate for 9 New Units / per Month	(a)	$	109
3	Monthly Rental Rate per Unit (Line 1 / 9 Units)			12
4	Rent Expense for October 2005 Installation - 3 Units for 3 Months	Line 3 * 3 * 3		108
5	Rent Expense for November 2005 Installation - 6 Units for 2 Months	Line 3 * 6 * 2		144
6	Sub-Total Operating Rents for DG Units in 2005			252
	O&M Expense			
7	Add: Phone Line Lease - ($1,890 per month, per site)	(a)		9
8	Unit Monitoring and Coordination ($1,800 / month)	"		5
9	Site Security and Escorts - ($600 /month)	"		2
10	Annual Source Test / Permit Fees (9 units)	"		46
11	Energy Projects Department Updated Labor Expense Estimate	(b)		256
12	Energy Projects Department Updated Non-Labor Expense Estimate	"		196
13	Less: Energy Projects Dept. Initial Labor Expense Estimate	HECO-702		(238)
14	Less: Energy Projects Dept. Initial Non-Labor Expenes Estimate			(134)
15	Sub-Total Other O&M Expenses for DG Units			142
16	**CA ADJUSTMENT TO INCLUDE ESTIMATED EXPENSES FOR NEW DISTRIBUTED GENERATION**		**$**	**394**

Footnotes:

(a) Detailed Estimate of DG O&M Costs provided by HECO in Attachment 1A to May 5, 2005 Test Year Rate Case Updates Letter at page 8.

(b) Attachment 1A, page 9, Increased Labor costs assumed to be met by suspension of CHP activity.

(c) Rate base investment is included in Adjustment B-8, See CA-311 as part of 2005 capital additions in the amount of $2,107,800.
Fuel inventory allowance of 500 barrels of #2 diesel added to Adjustment B-4

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
PRODUCTION OPERATIONS EXPENSE
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR AMOUNT	ADJUSTMENT AMOUNTS
	(A)	(B)	(C)	(D)
1	Normalize for Average 2005 Production Operations Staffing	CA-WP-101-C8,9		$ (218)
2	Non-labor Production Operations Expense Adjustments:			
3	**Kahe City Water expenses - Company Projected Amount**	CA-IR-664	$ 286	
4	Kahe City Water expenses - Corrected 2005 Estimate	"	185	
5	CA Adjustment for Kahe City Water Expenses	Line 4 - line 3	(101)	(101)
6	**Department of Health Emission Fees - Company Estimated**	HECO T-6, p.21	820	
7	HECO Factor to Normalize for Fee Waivers (7/10 or 70%)	"	70%	
8	HECO Proposed "Normalized" Emission Fees	Line 6 * Line 7	574	
9	Actual Department of Health Fees Paid in 2005 - Kahe Station	CA-IR-643	476	
10	Waiau Station	"	314	
11	Honolulu Station	"	52	
12	Total Actual Emission Fees Paid in 2005	Sum Lines 9..11	842	
13	CA Factor no Normalize for Fee Waivers (3/5 or 60%)	CA-T-1	60%	
14	CA Proposed "Normalized" Emission Fees	Line 12 * Line 13	505	
15	CA Adjustment for DOH Emission Fee Expenses	Line 14 - Line 8	(69)	(69)
16	**Sun-Power For Schools R&D Funding - Company Estimated**	CA-IR-186	75	
17	CA Adjustment to Eliminate Sun Power for Schools Expense	Line 16	(75)	(75)
18	**Electric Shock Absorber R&D Funding - Company Estimated**	CA-IR-2, T-6, ATT.5, p5	500	
19	CA Adjustment to Eliminate Electronic Shock Absorber R&D Costs	Line 18	(500)	(500)
20	**Test Year Amortization of Kahe 7 Regulatory Asset - per HECO**	CA-IR-2, T-6, ATT.3D p3	900	
21	Remaining Unamortized Balance at December 31, 2005	DOD/HECO-IR-6-12	675	
22	4 Year Amortization Required to Fully Recover Unamortized $ Under New Rates		4	
23	Rescheduled Amortization of Kahe 7 Regulatory Asset to Provide Full Recovery	Line 21 / Line 22	169	
24	CA Adjustment to Kahe 7 Amortization Expense to Prevent Over-recovery	Line 23 - Line 20	(731)	(731)
25	**Consulting Costs - Purchased Power Tolling Studies**	DOD/HECO-IR-6-13	75	
26	CA Adjustment to Eliminate Purchased Power Tolling Studies	Line 25	(75)	(75)
27	**CA ADJUSTMENT TO NORMALIZE AND CORRECT PRODUCTION OPERATIONS EXPENSE**			**$ (1,769)**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
PRODUCTION MAINTENANCE EXPENSE
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR AMOUNT	ADJUSTMENT AMOUNTS
	(A)	(B)	(C)	(D)
1	Normalize for Average 2005 Production Maintenance Staffing	CA-WP-101-C8,9		$ (1,194)
2	Non-labor Production Maintenance Expense Adjustments:			
3	Lowest Priority Discretionary Maintenance of Structures Items	CA-IR-244, page 2		
4	Honolulu Building Repairs	"	$ 60	
5	Kahe 1-6 Structural Painting	"	150	
6	Kahe Corrosion Control	"	40	
7	Kahe Demin Structural Maintenance	"	30	
8	Kahe Waste Water Structural Maintenance	"	60	
9	Waiau Paint - Corrosion Control	"	200	
10	Waiua Shop Building Repairs	"	150	
11	Total of Lowest Priority Maintenance of Structures Projects	Sum Lines 3..10	690	
12	CA Adjustment to Eliminate Lowest Priority Projected Non-labor Maintenance Expenses		(690)	(690)
13	CA Adjustment to Recognize Betterment Accounting Method Change	CA-IR-641		490
14	**CA ADJUSTMENT TO NORMALIZE PRODUCTION MAINTENANCE EXPENSE**			**$ (1,394)**

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
DEPRECIATION EXPENSE ADJUSTMENT
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Adjusted Annual Depreciation Expense on December 31, 2004:		
2	Actual Plant in Service Investment	CA-IR-514	$ 80,080
3	Less: HECO Prefiled Depreciation Accrual	HECO-1608	81,474
4	**CA ADJUSTMENT TO REVISE TEST YEAR DEPRECIATION EXPENSE ACCRUALS**	Line 1 - Line 2	**$ (1,394)**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
AMORTIZATION OF CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Updated Annual Amortization of Contributions in Aid of Construction CIAC	CA-IR-515	$ 7,484
2	HECO Prefiled Amortization of CIAC	HECO-1608	7,510
3	CA ADJUSTMENT TO REFLECT UPDATED CIAC AMORTIZATION	Line 2 - Line 1	26
4	Updated 2005 Amortization of SFAS 109 Regulatory Assets	CA-IR-516	814
5	Less: HECO Prefiled SFAS Regulatory Asset Amortization	HECO-1608	808
6	Adjustment to SFAS 109 Regulatory Asset Amortization	Line 5 - Line 6	6
7	**TOTAL CA ADJUSTMENT TO AMORTIZATION EXPENSE**	Line 3 + Line 6	**$ 32**

Witness: M. Brosch

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
* RESERVED *
FOR THE FORECAST 2005 TEST YEAR

Exhibit CA-101
Schedule C-12
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1			
2	***INTENTIONALLY LEFT BLANK***		
3			
4			

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
UNCOLLECTIBLE EXPENSE
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	CA Pro Forma Total Revenues (present rates)	(a)	$ 1,251,142
2	Times: CA Proposed Uncollectible Factor (4-yr avg)	(b)	0.0946%
3	CA Proposed Uncollectible Expense	Line 1 * Line 2	$ 1,183
4	Less: HECO Forecast Uncollectible Expense	(c)	(1,292)
5	**CA ADJUSTMENT TO NORMALIZE UNCOLLECTIBLE EXPENSE**	Line 3 + Line 4	**$ (109)**

Footnotes:
(a) Source: CA Schedule C, page 1.
(b) Uncollectible Factor:

	Net Write-Offs	Electric Sales Revenues	Total Operating Revenues	Electic Sales Ratio	Total Revenue Ratio
2000	$ 837,710	$ 832,703,418	$ 835,566,560	0.1006%	0.1003%
2001	774,636	901,109,340	904,038,912	0.0860%	0.0857%
2002	764,392	848,703,305	851,525,336	0.0901%	0.0898%
2003	975,434	950,236,663	952,970,294	0.1027%	0.1024%
2004	534,055	990,269,239	992,965,609	0.0539%	0.0538%
Average	$ 777,245	$ 904,604,393	$ 907,413,342	0.0859%	0.0857%
Average (excl 2004)	$ 838,043	$ 883,188,182	$ 886,025,276	0.0949%	**0.0946%**

Source: HECO response to CA-IR-75 & HECO monthly operating report.

(c) Source: HECO-901.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
SOFTWARE COSTS
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Software Costs:		
2	Human Resources Suite, Development Costs	(a)	$ 184
3	Ellipse, 2007 Software Upgrade	(b)	161
4	Ellipse, Maintenance Buy-Down Fee	(c)	401
5	HECO Test Year Forecast	(d)	$ 746
6	**CA ADJUSTMENT TO REMOVE HRS & ELLIPSE COSTS**		**$ (746)**

Footnotes:

(a) Source: HECO responses to CA-IR-352 & CA-IR-661.

(b) Source: HECO-1309.

(c) Ellipse, Maintenance Buy-Down Fee

Total Buy-Down Fee	$ 1,100	
Hawaii General Excise Tax	1.04166	
Total Buy-down Cost	$ 1,146	
HECO Allocation %	70%	
HECO Share	$ 802	
Payback/ Amortization Period	24	mos.
Monthly Amortization	$ 33	
Times: Test Year Months	12	mos.
HECO 2005 Test Year Amortization	$ 401	

Source: HECO-1604, pages 16-18.

(d) Forecast Distribution Recap:

	HRS	Ellipse Upgrade	Ellipse Buy-Down	Total
Production - O&M Nonlabor		$ 9	$ 59	$ 68
Transmission		5	4	9
Substation		1	2	3
Lines		3	8	11
Misc Distribution		12	-	12
Adm & Gen	$ 184	131	327	643
Total	$ 184	$ 161	$ 401	$ 746
		(b)	(c)	

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
LEASE AGREEMENT REVISIONS
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION		REFERENCE	AMOUNT
	(A)		(B)	(C)
1	REVISED OFFICE LEASES			
2	Central Pacific Plaza (CPP)			
3	Suite 700		(a)	$ 206
4	Suite 1010		(a)	117
5	Suite 1020, 1025 & 1075		(a)(b)	116
6	Suite 1201 & 1212		(a)	16
7	Suite 1250 & 1270		(a)(b)	9
8	Suite 1300		(a)	264
9	Suite 1425		(a)(b)	71
10	Suite 1480		(a)	32
11	Suite 1515		(a)	19
12	Suite 1520 & 1530		(a)	67
13	Suite 1570		(a)	77
14	HEIPC Sublease		(a)	41
15	Total - Central Pacific Plaza			1,035
16	King Street		(c)	506
17	Honolulu Club		(a)	78
18	Pacific Tower 8th floor		(a)	54
19	Waiau Viaduct		(a)	32
20	Pauahi Tower		(a)(b)	453
21	Total Lease Cost			2,158
22	Less: HECO Lease Cost (Original Forecast)	A/C 931	(d)	(1,557)
23	**CA ADJUSTMENT TO RECOGNIZE UPDATED LEASE RATES,**			**$ 601**
24	**NEW SPACE & OPERATING LEASE TREATMENT FOR THE KING**			
25	**STREET BUILDING**			

Footnotes:

(a) Source: HECO's response to CA-IR-260 (revised 6/9/05).

(b) New lease space negotiated since HECO's original filing.

(c) King Street Building: (treated as an operating lease for ratemaking purposes)

Annual Lease Payment	$ 775,000	[1]
GIT on Lease Payment	32,294	
Total Annual Rent	807,294	
Less: HEI Rent	(301,365)	
Annual Rent -- HECO	$ 505,929	
Total Building SF	58,313	[2]
Monthly Base Rent/ SF	$ 1.15	[1] / [2] / 12 mos.
Monthly CAM/ SF	1.50	estimated operating expense
PSC tax and PUC fees	0.18	(1.15+1.50) x .0682
Total $/SF	$ 2.83	
Times: HEI sq. ft.	8,874	
Monthly HEI rent	$ 25,114	
Annual HEI rent	$ 301,365	

(d) Source: HECO-1605.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
ALLOCATION OF HEI CHARGES TO HECO
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule C-16
Page 1 of 1

LINE NO.	DESCRIPTION		REFERENCE	AMOUNT
	(A)		(B)	(C)
1	A&G Expenses			
2	Increase HEI charges	A/C 921	(a)	$ 99
3	Decrease HEI charges in account 184120	A/C 921	(a)(b)	(17)
4	Increase HEI charges & Delete EICP Adm Costs	A/C 926000	(a)	(52)
5	Increase HEI charges	A/C 931	(a)	2
6	Total A&G Expense		Sum Lines 2..5	$ 32
7	**CA ADJUSTMENT TO RECOGNIZE UPDATED FORECAST**		Line 6	**$ 32**
8	**OF HEI CHARGES ALLOCABLE TO HECO**			

Footnotes:

(a) Source: HECO response to CA-IR-419 & HECO's June 15, 2005 Update Letter (Attachment 9).

(b) Per Attachment 9 [see Footnote (a)], adjustments to 184120 would normally be cleared to various accounts, however, to simplify matters, the adjustments are multiplied by 92%.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
REMOVE DSM PROGRAM COSTS
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule C-17
Page 1 of 1

LINE NO.	DESCRIPTION		REFERENCE	AMOUNT
	(A)		(B)	(C)
1	HECO 2005 DSM Forecast	A/C 910	(a)	$ 30,253
2	HECO Forecast -- IRP Planning Costs		(b)	1,303
3	IRP Administrative Costs -- Base Rate Includable		(b)	(685)
4	HECO IRP Incremental & DSM Program Costs/Incentives		Sum Lines 1..3	$ 30,871
5	**CA ADJUSTMENT TO REMOVE IRP INCREMENTAL PLANNING COSTS,**			**$ (30,871)**
6	**DSM PROGRAM COSTS & INCENTIVES TO BE CONSIDERED IN HPUC**			
7	**DOCKET NO. 05-0069.**			

Footnotes:

(a) Source: HECO-WP-1104, p. 1 of 12, & HECO-1014.

(b) IRP Planning Costs:

Base IRP		
Misc. Other Power Generation	A/C 549	$ 2
Misc. Distribution	A/C 588	4
Customer Assistance	A/C 910	390
Informational advertising	A/C 911	5
A&G - Labor	A/C 920	192
A&G - NonLabor (On-Costs)	A/C 921	92
Total Base IRP Planning Costs		685
Incremental IRP (normalized)		
Labor	A/C 920	58
Non-Labor (normalization)	A/C 921	560
Total CIDLC		618
Total IRP Planning Costs		$ 1,303

Source: HECO-1027 through HECO-1029.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
RATE CASE EXPENSE
FOR THE FORECAST 2005 TEST YEAR

Exhibit CA-101
Schedule C-18
Page 1 of 1

LINE NO.	DESCRIPTION		HECO ORIGINAL FORECAST (c)	HECO REVISED FORECAST (b)	CA PROPOSED
	(A)		(B)	(C)	(D)
1	Legal Fees	(b)	$ 205,000	$ 377,000	$ 205,000
2	Consultant - Rate Design		30,000	-	-
3	Consultant - Return on Equity		30,000	59,000	59,000
4	Consultant - Rate of Return on Rate Base		-	40,000	40,000
5	Consultant - DSM		-	157,000	-
6	Stenographer		10,000	10,000	10,000
7	Consultant - HEI impact (affidavit)		8,000	16,000	16,000
8	Supplies		1,000	3,000	3,000
9	Printing Services		-	10,000	10,000
10	Total 2005 Rate Case Expenses		$ 284,000	$ 672,000	$ 343,000
11	Amortization period				4
12	CA Proposed Annual Amortization	(c)			$ 85,750
13	Less: HECO Amortization (Original Forecast)				(94,667)
14	**CA ADJUSTMENT TO AMORTIZE RATE CASE EXPENSE**			A/C 928	**$ (8,917)**
15	**OVER A FOUR-YEAR PERIOD**			($000's)	**$ (9)**

Footnotes:

(a) Source: HECO response to CA-IR-258.

(b) As discussed in CA-T-2, legal costs have been reduced to HECO's original estimate pending receipt of the Company's rebuttal testimony disclosing the apportionment of the revised legal fees between the rate case and DSM Docket No. 05-0069.

(c) Source: HECO-1603.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
CUSTOMER SERVICE REORGANIZATION
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	DESCRIPTION		REFERENCE	AMOUNT
	(A)		(B)	(C)
1	Labor	A/C 910	(a)	$ 480,660
2	Non-Labor	A/C 910	(a)	24,000
3	Total Customer Solutions Reorganization			$ 504,660
4	**CA ADJUSTMENT TO RECOGNIZE THE CUSTOMER**		($000's)	**$ 505**
5	**SERVICE REORGANIZATION**			

Footnotes:
(a) Source: HECO response to CA-IR-78 & DOD/HECO-IR-9-2.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
STANDARD LABOR RATES & OVERTIME PAY
FOR THE FORECAST 2005 TEST YEAR

Exhibit CA-101
Schedule C-20
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Overtime Pay		
2	Direct to O&M Expense Accounts	(a)	$ 220,388
3	Distributed to O&M through Clearing Accounts	(a)	25,250
4	Total Labor Cost		245,638
5	Payroll Taxes	7.650%	18,791
6	Total		$ 264,429
7	**CA ADJUSTMENT TO REVISE OVERTIME MIX IN**	($000's)	**$ (264)**
8	**DEVELOPMENT OF STANDARD LABOR RATES**		

Footnotes:

(a) Source: HECO responses (CA-IR-76, DOD/HECO-IR-9-18) & May 5, 2005, Update Letter.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
AVERAGE EMPLOYEE LEVELS
FOR THE FORECAST 2005 TEST YEAR

LINE NO.		DESCRIPTION (A)	Total All Departments (B)	Less: Production (C)	Non-Production (D)	"Even Hiring Lag" O&M Adjustment (E)
1		Non-O&M Accounts	$ 2,059,713	$ -	$ 2,059,713	
2	500-514	Production Expense	$ 3,125,421	$ 3,087,204	$ 38,217	$ 19,108
3	561-571	Transmission Expense	269,133	-	269,133	134,566
4	581-598	Distribution Expense (b)	371,840	-	371,840	185,920
5	901-903	Customer Accounts Expense	407,404	-	407,404	203,702
6	910	Customer Service Expense	544,588	-	544,588	272,294
7	920-9302	A&G Expense	401,596	-	401,596	200,798
8		Total Payroll Expense	5,119,981	3,087,204	2,032,777	1,016,388
9	926	Employee Benefits	1,166,208		1,166,208	583,104
10		Total O&M Expense	$ 6,286,189	$ 3,087,204	$ 3,198,985	$ 1,599,492
11		Total All Accounts	$ 8,345,902 (a)	$ 3,087,204 (a)	$ 5,258,698 (a)	

12 **CA ADJUSTMENT TO RESTATE THE TEST YEAR FORECAST** ($000's) **$ (1,599)**

13 **TO RECOGNIZE AVERAGE NON-PRODUCTION EMPLOYEE LEVELS**

Footnotes:

(a) Source: HECO response to DOD/HECO-IR-8-8.

(b) Distribution Recap:

		Total Depts.	Production	Non-Production	Adjustment
581	Load Disp - Distr Op	$ 165,915		$ 165,915	$ 82,957
582	Station Exp - Distr Op	9,719		9,719	4,859
583	O/H Line Exp - Distr Ops	13,851		13,851	6,926
584	Underground Line Exp - Distr Ops	9,938		9,938	4,969
586	Meter Exp - Distr Ops	5,812		5,812	2,906
588	Misc Distr Ops Exp	95,035		95,035	47,518
592	Maint Substation - Distr	24,610		24,610	12,305
593	Maint O/H - Distr Maint	7,900		7,900	3,950
594	Maint Underground - Distr	27,597		27,597	13,799
595	Maint Line Trans	7,864		7,864	3,932
598	Maint Misc Distr Plant	3,599		3,599	1,800
	Total Distribution Expense	$ 371,840	$ -	$ 371,840	$ 185,920

Source: HECO response to DOD/HECO-IR-8-8.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
EMPLOYEE BENEFITS
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule C-22
Page 1 of 1

LINE NO.	DESCRIPTION	REVISED 2005 FORECAST	ORIGINAL 2005 FORECAST	DIFFERENCE	INCLUDED IN OTHER CA ADJUSTMENTS	NET ADJUSTMENT AMOUNT
	(A)	(B)	(C)	(D)	(E)	(F)
	A/C 926000: Employee Pensions and Benefits					
1	Qualified Pension Plan	$ 4,588	$ 4,349	$ 239	$ -	$ 239
2	Non-Qualified Pension Plans	-	-	-		-
3	Other Postretirement Benefits	7,138	6,827	311		311
4	Long-Term Disability Benefits	598	684	(86)		(86)
5	Other Benefits/Administration	720	849	(129)	52	(181)
6	Subtotals: Non-Labor	13,044	12,709	335	52	283
7	Labor	562	562	-		-
8	Total 926000	$ 13,606	$ 13,271	$ 335	$ 52	$ 283
	A/C 926010: Employee Benefits-Flex Credits					
9	Flex Credits Less Prices	$ (1,121)	$ (1,289)	$ 168	$ -	$ 168
10	Group Medical Plan	7,991	8,310	(319)		(319)
11	Group Dental Plan	1,222	1,183	39		39
12	Group Vision Plan	185	190	(5)		(5)
13	Group Life Insurance Plan	1,223	1,111	112		112
14	Other/Administration	300	245	55		55
15	Subtotals: Non-Labor	9,800	9,750	50	-	50
16	Labor	61	61	-		-
17	Total 926010	$ 9,861	$ 9,811	$ 50	$ -	$ 50
18	926020 Employee Benefits Transfer	$ (7,360)	$ (7,239)	$ (121)	$ -	$ (121)
19	Grand Total Charged to O&M	$ 16,107 (a)	$ 15,843 (a)	$ 264	$ 52 (b)	
20	**CA ADJUSTMENT TO EMPLOYEE BENEFIT COSTS TO**				Line 8 + 17 + 18	**$ 212**
21	**RECOGNIZE UPDATED PARTICIPANT DATA, PREMIUM RATES**					
22	**& ACTUARIAL STUDY RESULTS**					

Footnotes:

(a) Source: June 15, 2005 Update Letter (Attachment 8) & DOD/HECO-IR-9-2(o).

(b) CA Adjustment C-29.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
AMORTIZATION OF DEBT-RELATED COSTS
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Amortization: Bond Discount, Income Differential & Issuance Exp.	(a)	$ 1,521,000
2	Composite Federal/State Income Tax Rate		38.9098%
3	Income Tax Savings		$ 591,817
4	**CA ADJUSTMENT TO REFLECT THE AMORTIZATION OF**	($000's)	**$ (592)**
5	**DEBT-RELATED COSTS IN QUANTIFYING PRO FORMA**		
6	**INCOME TAX EXPENSE**		

Footnotes:

(a) Source: HECO-2103 & HECO-2104, revised May 5, 2005.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
RESEARCH & DEVELOPMENT
FOR THE FORECAST 2005 TEST YEAR

LINE NO.	DESCRIPTION		REFERENCE	AMOUNT
	(A)		(B)	(C)
1	EPRI Tailored Collaboration (TC) Funding,	A/C 9302	(a)	$ 96,500
2	Green Power Program,	A/C 910	(b)	100,000
3	Total Customer Solutions Reorganization			$ 196,500
4	**CA ADJUSTMENT TO REMOVE SELECTED R&D**		($000's)	**$ (197)**
5	**PROGRAM COSTS FROM THE 2005 FORECAST**			

Footnotes:

(a) Source: HECO response to CA-IR-536 & DOD/HECO-IR-9-2.
(b) Source: HECO T-10, p.4, & HECO response to CA-IR-79.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
KPMG AUDIT / SOX CHARGES
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HECO Updated Sarbanes-Oxley (SOX) Audit Fees	(a)	$ 754
2	HECO SOX Audit Fees (Original Forecast)	(a)	(373)
3	**CA ADJUSTMENT TO UPDATE SOX AUDIT FEES**	A/C 923020	**$ 381**

Footnotes:

(a) Source: HECO responses to CA-IR-424, DOD/HECO-IR-9-2 & HECO May 5, 2005, Update Letter.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
TAXES OTHER -- SUTA REDUCTION
FOR THE FORECAST 2005 TEST YEAR
($000's)

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	HECO SUTA Tax Expense (Original Forecast)	(a)	$ 202
2	**CA ADJUSTMENT TO REMOVE SUTA TAX EXPENSE**		**$ (202)**
3	**FROM THE FORECAST TEST YEAR**		

Footnotes:

(a) Source: HECO T-17, p. 4, & May 5 Update Letter.

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
INTEREST EXPENSE DEDUCTION
FOR THE FORECAST 2005 TEST YEAR
($000's)

Exhibit CA-101
Schedule C-27
Page 1 of 1

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
	(A)	(B)	(C)
1	Interest Expense on Long-Term Debt	(a) (c)	$ 24,953
2	Interest Expense on Short-Term Debt (A)	(b)	1,310
3	Interest Expense on Hybrid Securities	(a) (c)	2,051
4	Less: AFUDC Debt Interest	(d)	(1,924)
5	Net Interest Expense, Revised 5/5/05	Sum Lines 1..4	26,390
6	Less: HECO "As Filed" Interest Expense	(e)	(26,224)
7	Net Adjustment to Interest Expense	Line 5 + Line 6	166
8	Composite Federal/State Income Tax Rate		38.9098%
9	**CA ADJUSTMENT TO REFLECT THE INCOME TAX**		**$ (65)**
10	**EFFECT OF THE CHANGE IN INTEREST EXPENSE**		
11	**DUE TO THE REVISED CAPITAL STRUCTURE**		

Footnotes:

(a) Source: HECO-2103 & HECO-2104, revised 5/5/05.

(b) STD Interest:

2005 Average STD Balance	$	37,429
STD Interest Rate		3.50%
STD Interest	$	1,310

Source: CA Schedule D & HECO-2102, revised 5/5/05.

(c) Interest on Long-Term Debt & Hybrid Securities exclude amortization of debt-related costs, which are considered in CA Adjustment C-30.

(d) AFUDC Debt Interest:

AFUDC Expenditures	$	6,749
Ratio of Debt to Total		28.51%
	$	1,924

Note: HECO revised the AFUDC Debt Computation (based on updated Captial expenditures provided in Attachment 6, as revised on 6/15/05).

(e) Source: HECO-1702 & HECO-WP-1702, p.2, as filed.

(f) Interest Synchronization Impact:

CA Proposed Rate Base	$	1,065,201	CA Sch. A
CA Weighted Cost of Debt		2.6%	CA Sch. D
Imputed Interest Expense	$	27,589	
Less: Allocated Interest		(26,390)	Line 5, above
Additional Interest Included In Rates		1,199	
Composite Income Tax Rate		38.9098%	
Income Tax Effect	$	(466)	

Witness: S. Carver

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 04-0113
CAPITAL STRUCTURE & COSTS
FOR THE FORECAST 2005 TEST YEAR
(000's)

Exhibit CA-101
Schedule D

LINE NO.	DESCRIPTION	CAPITAL AMOUNTS	CAPITAL RATIO	COST RATES (a)	WEIGHTED COST
	(A)	(B)	(C)	(D)	(E)
	HECO Proposed (a)				
1	Short-Term Debt	$39,929	3.47%	3.50%	0.12%
2	Long-Term Debt	424,262	36.85%	6.30%	2.32%
3	Hybrid Securities	27,303	2.37%	7.55%	0.18%
4	Preferred Stock	20,476	1.78%	5.54%	0.10%
5	Common Equity	639,455	55.54%	11.50%	6.39%
6	Total Capitalization	$1,151,425	100.00%		**9.11%**
	CA Proposed (b)				
7	Short-Term Debt	$37,429	3.25%	3.50%	0.11%
8	Long-Term Debt	423,565	36.81%	6.25%	2.30%
9	Hybrid Securities	27,303	2.37%	7.55%	0.18%
10	Preferred Stock	20,476	1.78%	5.54%	0.10%
11	Common Equity (midpoint)	641,955	55.79%	9.25%	5.16%
12	Total Capitalization	$1,150,728	100.00%		**7.85%**

Footnotes :

(a) Source: HECO-2101.

(b) Source: Exhibit CA-612, sponsored by CA witness David Parcell **(CA-T-4).**
The recommended range for the cost of common equity is 8.5% to 10.0%, with a midpoint of 9.25%. The CA's proposed weighted cost of capital ranges from 7.43% to 8.27%, with a midpoint of 7.85%.

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**Asserted Revenue Requirement**			$ 98,614
2	SCH. B	**Return Difference At HECO Rate Base** (before pro forma working cash)	$ 1,104,784	-2.280%	(25,189)
3		Subtotal Revenue Requirement			$ 73,425
				PRE-TAX RETURN	
4		RATE BASE ADJUSTMENTS			
5	B-1	UPDATE OF NET PLANT ADDITIONS	(8,264)	14.10%	($1,165)
6	B-2	OTHER RATE BASE UPDATES	6,179	14.10%	871
7	B-3	ELIMINATION OF COMBINED HEAT & POWER PROJECTS	(4,959)	14.10%	(699)
8	B-4	DISTRIBUTED GENERATION RATE BASE INVESTMENT	1,054	14.10%	149
9	B-5	ELIMINATION OF CERTAIN PROPERTY HELD FOR FUTURE USE	(517)	14.10%	(73)
10	B-6	* RESERVED *	0	14.10%	0
11	B-7	SOFTWARE COSTS	(369)	14.10%	(52)
12	B-8	FUEL INVENTORY	14,959	14.10%	2,110
13	B-9	WORKING CASH ALLOWANCE	5,857	14.10%	826
14	B-10	PREPAID PENSION ASSET	(50,309)	14.10%	(7,095)
15		Total Value of Rate Base Adustments	(36,368)		(5,129)
16		Rate Base Recommendation (before pro forma working cash)	$ 1,068,416		
17		Change in Working Cash at Proposed Rates (HECO vs CA)	$ 9,958.94	16.39%	1,632
18		Rate Base With Working Cash Difference			$ (3,497)
19	SCH. A	**Adjusted Net Operating Income**	$ 44,625	**REVENUE CONVERSION MULTIPLIER**	
		NET OPERATING INCOME ADJUSTMENTS			
20	C-1	SALES VOLUME UPDATE ADJUSTMENT	925	1.7965	($1,662)
21	C-2	RATE RIDER DISCOUNT ADJUSTMENT	75	1.7965	(135)
22	C-3	SCHEDULE PP POWER FACTOR CORRECTION	398	1.7965	(714)
23	C-4	FUEL EXPENSE & ENERGY COST ADJUSTMENT SYNCHRONIZATION	1,561	1.7965	(2,804)
24	C-5	GAIN ON SALE AMORTIZATION	18	1.7965	(33)
25	C-6	ELIMINATION OF COMBINED HEAT & POWER PROJECTS	62	1.7965	(112)
26	C-7	INCREASE EXPENSE FOR DISTRIBUTED GENERATION	(241)	1.7965	432
27	C-8	PRODUCTION OPERATIONS EXPENSE	1,081	1.7965	(1,942)
28	C-9	PRODUCTION MAINTENANCE EXPENSE	852	1.7965	(1,530)
29	C-10	DEPRECIATION EXPENSE ADJUSTMENT	852	1.7965	(1,530)
30	C-11	AMORTIZATION OF CIAC	(20)	1.7965	35
31	C-12	* RESERVED *	0	1.7965	0
32	C-13	UNCOLLECTIBLE EXPENSE	66	1.7965	(119)
33	C-14	SOFTWARE COSTS	456	1.7965	(819)
34	C-15	LEASE AGREEMENT REVISIONS	(367)	1.7965	659
35	C-16	ALLOCATION OF HEI CHARGES TO HECO	(20)	1.7965	35
36	C-17	REMOVE DSM PROGRAM COSTS	18,859	1.7965	(33,881)
37	C-18	RATE CASE EXPENSE	5	1.7965	(10)
38	C-19	CUSTOMER SERVICE REORGANIZATION	(308)	1.7965	554
39	C-20	STANDARD LABOR RATES & OVERTIME PAY	162	1.7965	(290)
40	C-21	AVERAGE EMPLOYEE LEVELS	977	1.7965	(1,755)
41	C-22	EMPLOYEE BENEFITS	(130)	1.7965	233
42	C-23	AMORTIZATION OF DEBT-RELATED COSTS	592	1.7965	(1,063)
43	C-24	RESEARCH & DEVELOPMENT	120	1.7965	(216)
44	C-25	KPMG AUDIT / SOX CHARGES	(233)	1.7965	418
45	C-26	TAXES OTHER -- SUTA REDUCTION	123	1.7965	(222)
46	C-27	INTEREST EXPENSE DEDUCTION	65	1.7965	(116)
47		Total Value of Net Operating Income Adj.	25,931		$ (46,584)
48	SCH. A	Net Operating Income Recommendation	$ 70,556		
49		RECONCILED REVENUE REQUIREMENT			$ 23,343
50		UNRECONCILED DIFFERENCE			133
51	SCH. A	**REVENUE REQUIREMENT RECOMMENDATION**			$ 23,476

LINE NO.	DESCRIPTION	WEIGHTED COST (SCH. D)	REVENUE CONVERSION MULTIPLIER (a) (b)	PRETAX RETURN
	(A)	(B)	(C)	(D)
	RETURN PER HECO			
1	Short-Term Debt	0.12%	1.7986	0.216%
2	Long-Term Debt	2.32%	1.7986	4.173%
3	Hybrid Securities	0.18%	1.7986	0.324%
4	Preferred Stock	0.10%	1.7986	0.180%
5	Common Equity	6.39%	1.7986	11.493%
6	Total Capitalization	9.11%		16.386%
	RETURN PER CA			
7	Short-Term Debt	0.11%	1.7965	0.198%
8	Long-Term Debt	2.30%	1.7965	4.132%
9	Hybrid Securities	0.18%	1.7965	0.323%
10	Preferred Stock	0.10%	1.7965	0.180%
11	Common Equity (midpoint)	5.16%	1.7965	9.270%
12	Total Capitalization	7.85%		14.102%
13	DIFFERENCE IN PRE-TAX RETURNS			-2.280%

Source: CA Schedules D & A-1.

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WORKPAPERS TO

JOINT ACCOUNTING SCHEDULES

OF THE

CONSUMER ADVOCATE

PREPARED
BY
UTILITECH, INC.

Hawaiian Electric Company Inc.
Rate Case - Test Year 2005
Normalization of Average Production Department Labor

Line #	RA	Description	2005 TY	12/31/2004	Average	Difference	Adjustment Percentage Difference	Non-project Labor $000 (Att. 3): Operations Expensed Direct Labor	Non-project Labor $000 (Att. 3): Maintenance Expensed Direct Labor	Project Labor $000 (Att. 4): Operations Expensed Direct Labor	Project Labor $000 (Att. 4): Maintenance Expensed Direct Labor	Test Year Production O&M Labor $000: Operations Adjustment	Test Year Production O&M Labor $000: Maintenance Adjustment
		Average Staffing Calculations — Summary of Staffcounts per CA-IR-1; T-6; Attachment 5 (Note a)						**HECO Labor Cost Projections: CA-IR-1;T-6**				**CA Adjustment to Labor Costs**	
	Operations Personnel:												
1	PIA	Admin Services	5	5	5	0	**0.0%**	$ 153,368	$ 29,334			-	-
2	PIB	Admin PS O&M	10	7	8.5	-1.5	**-15.0%**	394,659	25,233			$ (59,199)	$ (3,785)
3	PIC	Purch Power	6	6	6	0	**0.0%**	267,991					-
4	PIF	Fuel	5	3	4	-1	**-20.0%**	40,839	11,458			(8,168)	(2,292)
5	PIH	Honolulu Operations	26	19	22.5	-3.5	**-13.5%**	1,534,711	-			(206,596)	-
6	PIK	Kahe Operations	58	59	58.5	0.5	**0.9%**	3,574,976	61,619			30,819	531
7	PIO	Operations Admin	1	3	2	1	**100.0%**	19,438				19,438	-
8	PIP	Planning	21	16	18.5	-2.5	**-11.9%**	310,091	831,606		6,161	(36,916)	(99,734)
9	PIW	Waiau Operations	62	64	63	1	**1.6%**	4,064,087	61,727			65,550	996
10		Total Operations	194	182	188	-6		10,360,160	1,020,977			(195,071)	(104,284)
11	**Maintenance Personnel:**												
12													
13	PIM	Mtce. Admin	2	2	2	0	**0.0%**	59,775	16,726			-	-
14	PIL	Kahe Maintenance	38	27	32.5	-5.5	**-14.5%**		2,378,578			-	(344,268)
15	PIN	Honolulu Maintenance	9	8	8.5	-0.5	**-5.6%**	14,145	528,175			(786)	(29,343)
16	PIT	Traveling Maintenance	74	66	70	-4	**-5.4%**	-	710,900		3,522,590	-	(228,837)
17	PIX	Waiau Maintenance	37	25	31	-6	**-16.2%**		2,282,448			-	(370,127)
18		Total Maintenance	160	128	144	-16		73,920	5,916,827			(786)	(972,575)
19													
20		Total Production Staffing	354	310	332	-22	**-6.2%**						

	Operations Adjustment	Maintenance Adjustment
Total Production Operations Expense Adjustment	$ (195,857)	
Total Production Maintenance Expense Adjustment		$ (1,076,859)
Add: Indirect Costs for Non-productive Hours (Note b) Direct Labor Times Non-productive Percentage	11.6%	10.9%
	(22,635)	(117,581)
Total Consumer Advocate Adjustment to Normalize for Average Staffing in Production Department	**$ (218,493)**	**$ (1,194,440)**

Footnotes:

(a) Other RA's charge labor costs to production O&M expenses that are not included in this calculation of staffing levels for the Production Department.

(b) Indirect costs include hours paid for vacations, holidays, sick leave, etc. % calculated from CA-IR-171, page 3:

	Production Operation	Production Maintenance	Total
Direct $	12,010	11,155	12,010
Indirect $	1,388	1,218	1,388
Total Labor	13,398	12,373	13,398
Indirect %	11.6%	10.9%	11.6%

Hawaiian Electric Company, Inc.

WORKING CASH ITEMS, 2005

($ in thousands)

Wording Cash at HECO Expense Levels

Summary of HECO-1907, with CA Revised Lag Day Values

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) HECO Annual Amount	(E) Average Daily Amount - Present (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per HECO - 904	See Footnotes Below			HECO WP-2301					
ITEMS REQUIRING WORKING CASH:										
Fuel Purchases	37	Note (a), (b)	16	21	p. 8	287,634	788	16,549	788	16,549
O&M Labor	37	Note (c) >>	11	26	p. 9	78,106	214	5,564	214	5,564
O&M Nonlabor	37	Note (d) >>	31	6	p. 9	115,332	316	1,896	316	1,896
ITEMS PROVIDING WORKING CASH:										
Purchased Power	37		39	(2)	p. 8	298,564	818	(1,636)	818	(1,636)
Revenue Taxes - Present Rates	37		90	(53)	p. 10	88,463	242	(12,845)		
Revenue Taxes - Proposed Rates	37		90	(53)	p. 7	97,202			266	(14,114)
Income Taxes - Present Rates	37		162	(125)	p. 7	10,759	29	(3,685)		
Income Taxes - Proposed Rates	37		162	(125)	p. 7	45,679			125	(15,643)
Total WORKING CASH								5,843		(7,385)
Change in WORKING CASH										(13,228)

Summary of Consumer Advocate Lag Day Revisions:

Note (a) Revenue Lag Revised per Page 2
Note (b) Response to CA-IR-524
Note (c) Response to DOD/HECO-IR-9-8.
Note (d) O&M Non-Labor Lag Revised per Page 3.

All Data per HECO-WP-904

Hawaiian Electric Company, Inc.
REVENUE LAG DAYS

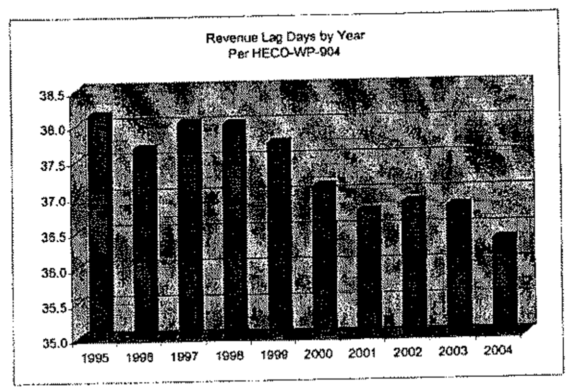
	1995				1996				1997				1998			
MONTH	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D
JAN	40,989	55,847	37.9	37.9	46,468	62,906	38.0	38.0	45,197	65,012	36.6	36.6	47,106	62,582	38.4	38.4
FEB	41,508	56,180	38.0	37.9	44,768	59,099	38.5	38.2	49,047	63,320	39.0	37.8	44,091	58,514	38.4	38.4
MAR	41,137	55,921	37.9	37.9	40,319	63,794	34.7	37.0	48,100	65,064	38.0	37.9	42,227	59,802	37.0	37.9
APR	38,922	57,166	36.2	37.5	38,112	55,925	36.2	36.8	46,860	66,025	37.1	37.7	41,856	57,280	37.7	37.9
MAY	41,874	56,685	38.0	37.6	44,694	61,206	37.7	37.0	48,169	62,033	39.1	37.9	40,440	54,954	37.9	37.9
JUN	43,560	59,997	37.6	37.6	45,237	65,763	36.4	36.9	46,355	64,384	37.4	37.9	41,280	57,792	37.2	37.8
JUL	48,263	60,140	39.9	37.9	50,791	67,784	38.3	37.1	48,756	64,911	38.3	37.9	42,700	59,120	37.5	37.7
AUG	44,503	63,644	36.8	37.8	48,503	65,615	38.0	37.2	47,869	65,009	37.9	37.9	43,253	60,382	37.3	37.7
SEP	48,758	63,577	38.8	37.9	51,092	67,209	38.6	37.4	49,497	69,605	37.1	37.8	45,531	61,343	38.1	37.7
OCT	43,975	62,987	36.7	37.8	49,263	66,000	38.2	37.5	49,038	66,785	37.8	37.8	44,568	58,222	38.8	37.8
NOV	45,002	62,238	37.5	37.7	50,672	67,935	38.2	37.5	50,479	63,504	39.7	38.0	46,547	62,322	38.2	37.9
DEC	47,912	52,413	43.3	38.1	50,688	65,553	39.0	37.7	47,311	62,588	38.5	38.0	46,562	58,501	39.7	38.0
YTD TOTALS	526,403	706,595			560,605	768,789			576,678	778,240			526,161	710,814		
YTD AVERAGE	43,867	58,883	38.1		46,717	64,066	37.7		48,057	64,853	38.0		43,847	59,235	38.0	

	1999				2000				2001				2002			
MONTH	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D
JAN	45,333	59,043	38.8	38.8	48,574	67,173	37.5	37.5	58,323	77,801	38.3	38.3	50,133	66,464	38.4	38.4
FEB	41,281	55,779	38.0	38.4	45,961	65,899	36.7	37.1	48,918	72,949	35.9	37.1	46,735	61,034	38.8	38.6
MAR	40,597	53,455	38.6	38.5	46,264	67,328	36.4	36.9	46,758	70,093	38.6	37.0	42,962	61,613	38.7	38.0
APR	38,679	55,248	36.8	38.1	46,969	67,745	36.6	36.8	48,521	70,860	36.3	36.8	42,270	66,367	34.9	37.2
MAY	39,821	57,690	36.5	37.7	48,381	70,074	36.5	36.7	47,447	71,013	35.8	36.6	45,327	67,154	36.0	36.9
JUN	43,733	58,927	38.1	37.8	49,771	72,643	36.3	36.7	49,035	72,949	35.9	36.5	48,837	73,422	35.7	36.7
JUL	43,342	60,333	37.3	37.7	53,288	75,366	37.0	36.7	52,372	77,371	36.1	36.4	51,733	76,198	36.1	36.6
AUG	44,112	63,451	36.6	37.6	54,869	76,952	36.8	36.7	53,998	78,070	36.5	36.5	51,600	75,815	36.2	36.6
SEP	47,946	62,654	38.8	37.7	56,248	76,972	37.7	36.8	56,128	81,759	36.4	36.4	53,196	77,522	35.4	36.5
OCT	46,505	64,645	37.4	37.7	54,791	79,057	36.6	36.7	56,517	77,777	37.6	36.6	55,187	79,002	36.7	36.6
NOV	46,220	65,287	38.0	37.6	56,863	77,718	37.7	36.9	55,596	72,901	38.7	36.7	56,611	77,134	38.6	36.8
DEC	50,911	69,096	37.9	37.7	59,344	75,279	39.5	37.1	54,563	78,070	36.7	36.7	57,269	76,889	38.1	36.9
YTD TOTALS	530,480	725,606			621,321	874,206			630,176	901,613			603,860	858,634		
YTD AVERAGE	44,207	60,467	37.7		51,777	72,851	37.1		52,515	75,134	36.7		50,322	71,553	36.9	

	2003				2004			
MONTH	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D	DAILY REC BAL	SALES REVENUES	LAG DAYS MONTH	LAG DAYS Y-T-D
JAN	59,568	77,216	39.0	39.0	58,219	80,025	37.6	37.6
FEB	52,948	74,068	37.2	38.1	56,388	78,885	37.2	37.4
MAR	52,626	78,274	35.9	37.4	57,410	79,306	37.5	37.5
APR	53,485	78,437	36.2	37.1	50,871	80,767	34.6	36.7
MAY	53,870	79,394	36.1	36.9	51,083	80,834	34.8	36.3
JUN	55,368	83,573	35.6	36.7				36.3
JUL	57,306	80,836	37.1	36.7				36.3
AUG	55,352	83,608	35.8	36.6				36.3
SEP	59,162	85,033	36.7	36.6				36.3
OCT	57,362	82,078	36.7	36.6				36.3
NOV	58,100	80,291	37.5	36.7				36.3
DEC	58,641	77,969	38.4	36.8				36.3
YTD								
TOTALS	673,786	960,776			273,971	399,617		
YTD AVERAGE	56,149	80,065	36.8		22,831	33,301	36.3	

SUMMARY OF ALL YEARS

Revenue Lag, by Year	
1995	38.1
1996	37.7
1997	38.0
1998	38.0
1999	37.7
2000	37.1
2001	36.7
2002	36.9
2003	36.8
2004	36.3
10 year avg	37.3
9 year avg	37.3



Hawaiian Electric Company, Inc.
Working Cash Study
Revised O&M Non-Labor Payment Lag

Source: HECO-WP-1907, page 28

	Test Year Expense ($000's)	% of Total	Total Payment Lag Days	Weighted Average
	Note A		HECO-WP-1907, p. 29-32	
Pension [1]	$0	0%	0	days
OPEB [2]	$0	0%	0	days
Emission Fees [3]	$505	0%	322	1 days
EPRI Dues [4]	$1,531	1%	-6	days
Other Non-Labor O&M [5]	$113,296	98%	30	30 days
	$115,332	100%		
O&M Non-Labor Payment Lag				**31 days**

Note A

[1] Pension expense was included at $0 expense level with zero lag days to neutralize any working cash impact.

[2] OPEB expense was included at $0 expense level with zero lag days to neutralize any working cash impact.

[3] Emission Fees based upon actual fees payable in 2005 per CA-IR-643, less 40% waiver allowance.

[4] EPRI Dues per HECO-1604, page 2.

[5] Other Non-Labor O&M = Total O&M Non-Labor expense of $115,332k, less other items noted above.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing **DIVISION OF CONSUMER ADVOCACY'S DIRECT TESTIMONIES, EXHIBITS AND WORKPAPERS** was duly served upon the following parties, by personal service, hand delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR § 6-61-21(d).

WILLIAM A. BONNET — 1 copy
VICE PRESIDENT, GOVERNMENT AND COMMUNITY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. BOX 2750
Honolulu, Hawaii 96740-0001

DARCY ENDO-OMOTO — 1 copy
ACTING DIRECTOR-RUGULATORY AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.
P. O. BOX 2750
Honolulu, Hawaii 96740-0001

THOMAS W. WILLIAMS, JR. — 1 copy
PETER Y. KIKUTA
GOODSILL ANDERSON QUINN & STIFEL
1800 Alii Place
1099 Alakea Street
Honolulu, Hawaii 96813

DR. KAY DAVOODI — 1 copy
Utilities Rates and Studies
NAVFAC Washington
1314 Harwood Street, S.E.
Washington Navy Yard, DC 20374-5018

RANDALL Y.K. YOUNG — 1 copy
Associate Counsel (Code 09C)
Naval Facilities Engineering Command, Pacific
258 Makalapa Drive, Suite 100
Pearl Harbor, HI 96830-3134

DATED: Honolulu, Hawaii, June 28, 2005.

Ann Tonokawa
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